NOTE

This Microfiche meets the quality requirements of the American National Standard for Microfiche of Documents (ANSI P.H5.9-1975). However, because of imperfections in the document from which it was made, it contains images that are illegible or difficult to read. The source document for this microfiche is the best copy that could be obtained prior to filming.

CIS

Congressional Information Service, Inc
Washington, D.C

CLEAN COAL TECHNOLOGIES INITIATIVE

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY DEVELOPMENT AND APPLICATIONS

OF THE

COMMITTEE ON
SCIENCE AND TECHNOLOGY
HOUSE OF REPRESENTATIVES

NINETY-NINTH CONGRESS

FIRST SESSION

MAY 8, 1985

[No. 25]

Printed for the use of the
Committee on Science and Technology

U.S. GOVERNMENT PRINTING OFFICE
50-513 O WASHINGTON : 1985

H701-87

COMMITTEE ON SCIENCE AND TECHNOLOGY

DAN FUQUA, Florida, *Chairman*

ROBERT A. ROE, New Jersey
GEORGE E. BROWN, Jr., California
JAMES H. SCHEUER, New York
MARILYN LLOYD, Tennessee
TIMOTHY E. WIRTH, Colorado
DOUG WALGREN, Pennsylvania
DAN GLICKMAN, Kansas
ROBERT A. YOUNG, Missouri
HAROLD L. VOLKMER, Missouri
BILL NELSON, Florida
STAN LUNDINE, New York
RALPH M. HALL, Texas
DAVE McCURDY, Oklahoma
NORMAN Y. MINETA, California
MICHAEL A. ANDREWS, Texas
BUDDY MacKAY, Florida**
TIM VALENTINE, North Carolina
HARRY M. REID, Nevada
ROBERT G. TORRICELLI, New Jersey
FREDERICK C. BOUCHER, Virginia
TERRY BRUCE, Illinois
RICHARD H. STALLINGS, Idaho
BART GORDON, Tennessee
JAMES A. TRAFICANT, Jr., Ohio

MANUEL LUJAN, Jr., New Mexico*
ROBERT S. WALKER, Pennsylvania
F. JAMES SENSENBRENNER, Jr., Wisconsin
CLAUDINE SCHNEIDER, Rhode Island
SHERWOOD L. BOEHLERT, New York
TOM LEWIS, Florida
DON RITTER, Pennsylvania
SID W. MORRISON, Washington
RON PACKARD, California
JAN MEYERS, Kansas
ROBERT C. SMITH, New Hampshire
PAUL B. HENRY, Michigan
HARRIS W. FAWELL, Illinois
WILLIAM W. COBEY, Jr., North Carolina
JOE BARTON, Texas
D. FRENCH SLAUGHTER, Jr., Virginia
DAVID S. MONSON, Utah

Harold P. Hanson, *Executive Director*
Robert C. Ketcham, *General Counsel*
Regina A. Davis, *Chief Clerk*
Joyce Gross Freiwald, *Republican Staff Director*

Subcommittee on Energy Development and Applications

DON FUQUA, Florida, *Chairman*

ROBERT A. ROE, New Jersey
RALPH M. HALL, Texas
FREDERICK C. BOUCHER, Virginia
TERRY BRUCE, Illinois
JAMES A. TRAFICANT, Jr., Ohio
DOUG WALGREN, Pennsylvania
ROBERT A. YOUNG, Missouri
DAVE McCURDY, Oklahoma
RICHARD H. STALLINGS, Idaho
GEORGE E. BROWN, Jr., California

F. JAMES SENSENBRENNER, Jr., Wisconsin
CLAUDINE SCHNEIDER, Rhode Island
RON PACKARD, California
HARRIS W. FAWELL, Illinois
WILLIAM W. COBEY, Jr., North Carolina
JOE BARTON, Texas
D. FRENCH SLAUGHTER, Jr., Virginia

---

*Ranking Republican Member.
**Serving on Committee on the Budget for 99th Congress.

CONTENTS

WITNESSES

May 8, 1985: Page

Hon. William A. Vaughan, Assistant Secretary for Fossil Energy, U.S. Department of Energy, Washington, DC; accompanied by Dick Harrington, Deputy Assistant Secretary for Coal Utilization 2

Prepared statement 5

Prepared statement of Hon. Marilyn Lloyd 23

Prepared statement of Hon. Marcy Kaptur 27

Discussion 31

Prepared statement of Hon. Dennis Eckart 40

Eric Reichl, chairman, Clean Coal Use Panel, Greenwich, CT 52

Report of ERAB Panel on Clean Coal Use Technologies 54

Prepared statement 207

Discussion 214

Gene G. Mannella, director, Washington office, Electric Power Research Institute, Washington, DC 220

Prepared statement 222

David O. Webb, senior vice president, Policy and Regulatory Affairs, Gas Research Institute, Washington, DC 263

Prepared statement 266

Discussion 279

Panel II:

John M. Wooten, director of research and technology, Peabody Holding Co., Inc., St. Louis, MO, testifying on behalf of the Clean Coal Technology Coalition 283

Prepared statement 286

John McCormick, Environmental Policy Institute, Washington, DC 305

Prepared statement 308

Discussion 321

Appendix I:

Additional statements for record:

American Gas Association 326

Alex Radin, executive director, American Public Power Association 335

Daniel Kleman, city manager, city of Tallahassee 337

Bern E. Deichmann, vice president, Marketing Transamerica Delaval, Inc 342

Edison Electric Institute 348

Charles S. McNeer, chairman of the board, Wisconsin Electric Power Co 360

Appendix II:

Additional questions and answers:

William Vaughan, Assistant Secretary, U.S. Department of Energy in response to request by Don Fuqua, Rick Boucher, Jim Sensenbrenner 366

Kurt Yeager, vice president, EPRI for Gene Mannella in response to request by Don Fuqua, Jim Sensenbrenner 434

Summary comments from Senate briefing, June 19, 1985 441

David O. Webb, senior vice president, Policy and Regulatory Affairs, Gas Research Institute, Washington, DC 457

John Wooten, director, research and technology, Peabody Holding Co., Inc 461

CLEAN COAL TECHNOLOGIES INITIATIVE

WEDNESDAY, MAY 8, 1985

House of Representatives,
Committee on Science and Technology,
Subcommittee on Energy Development and Applications,
Washington, DC.

The subcommittee met, pursuant to call, at 9:30 a.m., in room 2318, Rayburn House Office Building, Hon. Don Fuqua (chairman of the subcommittee) presiding.

Mr. Fuqua. The hearing today concerns the Clean Coal Technologies Initiative, an activity directed by Congress last year and concluded recently by the U.S. Department of Energy. We will also consider a recently completed report on clean coal technologies prepared by DOE's Energy Research Advisory Board.

A summary of events during the past 12 months seems somewhat appropriate. In April of last year the Secretary of Energy requested that ERAB convene a panel to assess the principal technologies for clean use of coal. The requested report was accepted by ERAB on May 1, just about 1 week ago.

Later in 1984 Congress directed DOE to determine the private sector's interest in emerging clean coal technologies—those advanced concepts that could reduce the level of pollutants from coal-fired utility and large industrial plants.

The response to DOE's solicitation of interest was very impressive—176 statements involving 12 specific technologies and 1 nonspecific technology, located in 28 States and the District of Columbia, significant levels of cost sharing, and a large number of innovative, imaginative approaches. We have reviewed the DOE report and believe that it merits some discussion.

No one is surprised at the scope of the report. This committee has authorized funds for research and development in all the technologies addressed. Through hearings, oversight, and other contacts, we have heard both industry and Government justify expenditures on the bases of extension of knowledge, environmental impact, resource utilization, and ability to exercise options. We understand that now all processes are not equal in stage of development, but that eventually all processes will be available, through development, offering valuable freedom of choice.

Probably no one is surprised at the lack of depth of the report. We are disappointed that DOE has chosen to ignore the vigor and intelligence of the private sector's response. This report would seem to offer an excellent opportunity for DOE to provide technical advice on the assistance necessary to get a technology to the stage of commercialization. We certainly do not expect DOE to advise on commercialization. We leave that up to those risk-takers in industry who take the biggest risk when they attempt to commercialize. The administration should realize that risk does not end when development is complete.

We hope that our witnesses will provide the committee with constructive evaluation of the DOE report. We hope, also, that we can review the ERAB report on clean coal technologies, which I mentioned earlier. That report may eventually prove to be more helpful to the Congress than the report we have recently requested and received from DOE.

With information received today and at other congressional hearings, we should be able to arrive at means of using coal more cleanly, more economically, more efficiently, and more quickly.

The efforts all our witnesses have made to be with us is appreciated. We look forward to hearing from all of you.

Our first witness today will be Mr. William Vaughan, Assistant Secretary for Fossil Energy, who is identified by the Secretary as the DOE report implementer.

We welcome you, Bill, and await your testimony.

STATEMENT OF HON. WILLIAM A. VAUGHAN, ASSISTANT SECRETARY FOR FOSSIL ENERGY, U.S. DEPARTMENT OF ENERGY, WASHINGTON, DC, ACCOMPANIED BY DICK HARRINGTON, DEPUTY ASSISTANT SECRETARY FOR COAL UTILIZATION

Mr. VAUGHAN. Thank you, Mr. Chairman. Recognizing that you have several witnesses to follow this morning, I would like to submit my formal statement for the record and briefly summarize here some key points. I would like to discuss them in reverse order from the way that the formal statement is structured.

Also, I would like to point out to you, Mr. Chairman, that I have here at the table with me the Deputy Assistant Secretary for Coal Utilization, Mr. Dick Harrington. I also have other staff members here with us, so that we can answer the committee's questions in some detail.

First of all, Mr. Chairman, I want to stress what I believe has been the significant positive benefits that have resulted from this clean coal report effort. These are outlined in the final page of my formal statement, but I want to use them here at the beginning to emphasize the fact that we believe valuable and beneficial results have come from this effort.

First, the clean coal report we submitted to Congress last week represents a snapshot of industry's interest in new coal technologies. It has told us that industry is prepared to move forward with new concepts that offer significant environmental and economic advantages. While most of the submissions did indicate a need, or perhaps more accurately a desire to receive Federal funds, there are several projects that will likely move ahead on their own with little, if any, Federal incentives.

For many energy companies the exercise served as an organizing point to bring equipment manufacturers, architect-engineers and other related firms into project teams. Should some of the proposed projects proceed, many will incorporate a much wider diversity of research, manufacturing, and marketing interests that might otherwise have been the case,

The exchange of information between the private sector and the Government has also been an especially valuable project of this effort. We now in the Government have a better indication of the direction the coal industry would like to take in the development and application of new technology.

Finally, several interesting ideas emerged from the exercise that may be of value to future planning of the Government's coal research and development program. As we plan our fiscal 1987 and future programs, we will have the benefit of some of the new ideas expressed in several of the submissions in response to this request.

Mr. Chairman, the report we have prepared represents the Department's and the administration's commitment to be fully responsive to the Congress. We devoted some 12,000 staff hours within fossil energy alone, to the preparation of this report. More than 50 professional staff members from our headquarters, Morgantown and Pittsburgh Energy Technology Centers participated in this effort. Furthermore, we extended the due date for submissions at the request of the Congress, and then went what I consider to be a significant step further, in accepting late arriving submissions and incorporating them as much as possible into the final report.

We take a special measure of pride in appendix C of the report, the "Technology Assessments." Here is where we have tried to capture the key features of the technologies proposed and to profile their economic, environmental, and technological potential. In short, Mr. Chairman, we have completed a report which we believe fully complies with the congressional directive contained in Public Law 9873.

Now, having completed the required actions, Secretary Herrington has asked us to go yet another step further. As described on page 3 of my formal statement, we will attempt in a supplemental effort to provide fuller characterization of clean coal technologies. To do this, we will draw from this May 1 report, the recent report of the Energy Research Advisory Board, the International Energy Agency's most recent clean coal technology report, and other general background material.

We hope to characterize various coal technologies against a set of criteria such as environmental promise, cost, stage of development and scientific feasibility, to name a few. This additional information will be compiled into a final report and submitted to the Congress.

While we continue to recommend to the Congress that the Federal Government refrain from becoming a financial partner in large, demonstration-scale projects, we believe such an effort will, that is, the preparation of this additional report—will be helpful to the Department, to the Congress, and to the coal industry in determining the most productive approaches for development of clean coal technology.

In summary, Mr. Chairman, we are in wholehearted agreement with the objective of increasing the use of American coal in an environmentally acceptable manner. We believe that the Government has a legitimate research role in improving coal technologies and to make this increasing use technologically possible.

The administration's Research Program has been designed to bring about a more economical, cleaner technology for coal that will benefit the domestic coal market as well as our environment and our economy in general.

This concludes my opening remarks, Mr. Chairman. I will be pleased to answer any questions.

[The prepared statement of Mr. Vaughan follows:]

Statement of

WILLIAM A. VAUGHAN
Assistant Secretary for Fossil Energy
U.S. DEPARTMENT OF ENERGY

to the

Subcommittee on Energy Development and Applications
HOUSE COMMITTEE ON SCIENCE AND TECHNOLOGY

May 8, 1985

Mr. Chairman and Members of the Committee:

Seven months ago, as part of its Continuing Appropriations resolution, the Congress directed the Department of Energy to solicit indications of the private sector's interest in emerging clean coal technologies.

On May 1, 1985, following the evaluation of 175 responses, the Department of Energy delivered to the Congress a 271-page report in response to the Congressional directive. The report represents the product of more than 12,000 cumulative hours of professional staff involvement within the Office of Fossil Energy -- the largest single effort to produce a Congressional report ever undertaken by this office. The report has received the personal attention of Energy Secretary John S. Herrington and reflects both the Secretary's and the Administration's commitment to be fully responsive to Congress in this matter.

We are pleased to appear before the Committee this morning to summarize that report.*

BACKGROUND -- ANALYSIS PROCEDURES

Following enactment of Section 321 of Public Law 98-473, the Department published a Program Announcement in the Federal Register on November 27, 1984, requesting information on emerging clean coal technologies. Simultaneously the Department issued a press announcement describing this effort to more than 250 general, trade, and broadcast media outlets. On December 7, 1984, an insert was also placed in the Commerce Business Daily which called attention to the Department's interest in receiving clean coal technology information.

---

* NOTE: Several submitters identified part or all of their submissions as confidential and proprietary business information. To protect the submitters' material and to provide a complete report to Congress, all the confidential and/or proprietary submissions have been included in a supplemental volume that has been made available to the Congress.

Together, these actions were intended to maximize public awareness of the Department's clean coal technology announcement. By the February 15, 1986 deadline (which had been extended from January 18, 1986, in response to a request of the Congress), 167 statements of interest and informational proposals had been received from industry.

Once the deadline had passed for receipt of responses, it became evident that several submissions were still being prepared and would continue to arrive at the Department at later dates. To ensure that the Department's report to Congress was as complete as possible, I directed the Fossil Energy staff to incorporate the late responses into the report if this could be done without jeopardizing the preparation schedule.

In total, therefore, the Department had received 175 submissions at the time the report to Congress was prepared. A subsequent submission was received too late to be analyzed but is included in the summary portion of the report.

While many of the logging and tracking procedures were similar to a formal procurement evaluation, the Department could not adhere rigidly to competitive procurement guidelines. Since the Department neither requested nor was appropriated funds for any of the proposed activities, we made it clear to the submitters that they could not be reimbursed for any expenses they might incur in responding to the Department's announcement.

A senior staff team, made up of Fossil Energy Office Directors, was formed to sort the submissions upon receipt, assign them to the appropriate analysis team and provide specific instructions and guidance. Three separate analyses teams were formed, each led by a member of the Senior Executive Service.

These teams mirrored the major coal-related technical office subdivisions within the Office of Fossil Energy:

Coal Utilization Systems
Surface Coal Gasification Systems and
   Advanced Conversion Systems
Underground Coal Gasification and Coal Liquids.

For each team, technical and analytical skills were drawn from Fossil Energy personnel at Headquarters and the Morgantown and Pittsburgh Energy Technology Centers. The Offices of General Counsel and Procurement Support participated on a consulting basis. No personnel outside the employ of the Department participated in or had access to the review process in any way.

Having completed the required actions under Section 321 of P.L. 98-473, we would now like to explain our next steps in the clean coal area and the approach the Secretary has asked us to undertake. Our general approach will be to provide fuller characterizations of clean coal technologies using such information as the Section 321 submissions, information gained from our ongoing budget activities, the recent clean coal report by the Energy Research Advisory Board, and other general background material .

Specifically, the first effort will be to establish criteria against which the technologies could be evaluated. These criteria will include such things as environmental promise, cost, stage of development and scientific feasibility to name a few. Second, the technologies will then each be evaluated against the criteria. The pros and cons for each of these technologies will then be explained.

All of this additional information will be compiled into a final report and submitted to the Congress.

I believe that such an effort will be helpful to the Department, the Congress, and the coal industry in determining the most productive approaches for development of clean coal technology.

SUMMARY OF RESPONSES

As indicated earlier, 175 responses were received, with project values totalling in excess of $8 billion. Sixteen of the submissions did not propose specific projects but instead provided general information or support for individual projects or groups of projects, or endorsed the program in general.

Responses were received for every Fossil Energy coal technology program except one, waste management. Organizations in 28 states and the District of Columbia submitted statements of interest or informational proposals.

One hundred and five of the submissions identified specific locations for their proposed projects. The sites were located in 29 states.

The following table summarizes the submissions received by category of technology:

Technology	Number of Submissions
Flue Gas Cleanup[1]	31
Fluidized Bed Combustion[2]	27
Surface Coal Gasification	27
Coal Preparation	22
Heat Engines[2]	13
Advanced Combustion	10
Alternative Fuels	8
Fuel Cells	8
Coal Liquefaction	5
Underground Coal Gasification	4
Gas Stream Cleanup	2
Magnetohydrodynamics	2
Non-Technology Specific	16
	175

[1] One submitter proposed two projects, so that the total number of proposed projects is 32.

[2] One proposal was evaluated in two categories (Fluidized Bed Combustion and Heat Engines) because it contained technology development in both areas.

Flue Gas Cleanup

Of the 32 projects described in this category, 14 concentrated on in-boiler sulfur dioxide control using sorbents. Seven submissions were received on dry waste flue gas desulfurization processes. Five submissions described regenerable flue gas desulfurization processes and the remaining six represented a variety of miscellaneous approaches.

Most of the submissions were targeted at the large utility boiler market (the one exception was a coal-fired cogeneration process for the pulp and paper industry).

The requested federal incentives, with one exception, were for direct funding. The one exception asked instead for an innovative technology waiver of sulfur dioxide New Source Performance Standards for two new 572 MWe plants in return for installing the limestone injection multistage burner technology.

In two of the submissions, work has already been performed or likely will be completed regardless of federal funding. For 13 of the proposed projects that are similar to existing privately-funded ones, an argument was made for multiple demonstrations in order to provide greater confidence. Lastly, several submitters stated that their projects would not be initiated at all in the absence of federal support.

Advanced Combustors

Ten submissions were for projects that addressed advanced combustor technology. These submissions varied significantly in cost, duration, size and type of coal to be used; however, the projects could be grouped into two general categories: three submissions proposed relatively mature slagging combustor designs for utility retrofits, while seven projects would use less mature concepts that require further development before they would be ready for demonstration.

Proposed federal assistance was in the form of direct cost-sharing. Where justification for federal support was provided, it entailed the unavailability of private funds and the need to minimize risks for the first users of the technology.

Fluidized Bed Combustion

In the Atmospheric Fluidized Bed Combustion (AFBC) area, 21 responses were received (one was received too late for analysis and is included only in the summary section of the report).

Ten projects were targeted at utility applications at scales of 20 MWe to 235 MWe. Four would apply the circulating AFBC concept, three would use the bubbling bed AFBC concept, and three indicated that a decision between the two concepts had not yet been made.

Four projects were proposed at the industrial scale, i.e., 200,000 to 500,000 lb/hr of steam production. Three would apply the circulating bed technology to generate steam or for cogeneration, while one proposed the bubbling AFBC concept.

Six statements of interest were received for projects that did not fit in either the utility or industrial categories or were for research and development efforts. One additional project was designated as proprietary information by the submitter.

Many of the AFBC submissions did not provide justification for the federal incentives proposed, but those that did offered the following rationale for government funding support: (1) the hurdle of the significant capital cost differentials between atmospheric fluidized bed combustors and proven alternative technologies, (2) the need to offset partners' financial commitments and not as a condition to complete the project, and (3) in the case of immature technologies, to pay for the risks involved.

Six submissions were received in the Pressurized Fluidized Bed Combustion (PFBC) Technology area. Three were for steam-cooled combined cycle and turbocharged boiler systems, two were for advanced circulating fluidized bed PFBC technology, and one was to operate a federally-funded air-cooled circulating bed pilot plant which is currently being dismantled (the 13 MWe Wood Ridge, NJ, PFB pilot plant).

The submissions describing steam-cooled combined cycle projects stated that federal incentives would help offset the technology risk and initial high costs of repowering or retrofitting existing utility boilers. The project proponents state that demonstration of PFB technology under actual utility operating conditions and scale is essential to determine its performance and economics.

The three proposers suggesting circulating PFBC combined cycle concepts each identified further research that would be conducted at units considered to be at the pre-demonstration plant scale. This research would be necessary before scale up could occur.

Coal Preparation

Although 22 submissions were received in the category of Coal Preparation, only seven proposed demonstration projects. The remaining 15 were for technologies at scales less than demonstration.

Three of the demonstration projects were labeled as proprietary. The others proposed to clean coal with (1) microbubble column flotation followed by high speed centrifuge dewatering; (2) physical cleaning techniques, followed by hot water drying, and acid extraction; (3) high gradient magnetic separation; and (4) a combination of physical and microbial cleaning techniques.

The federal incentives requested were almost exclusively direct funding and were deemed necessary by the submitters (1) because internal funds were not available to support a demonstration project; and (2) to make the technology available to the industry by the late 1980s.

Alternative Fuels

Eight submissions were received in the alternative fuels category, and all involved the application of coal-water mixture technology. Two of the submissions were identified as "Confidential Proprietary Information" by the submitters, and one did not propose a specific project.

The remaining five projects proposed (1) the development of a slurry fuel by applying the oil agglomeration beneficiation technique, (2) the use of a model to study and maximize the efficient use of coal in a blast furnace, (3) the development of a coal-water-mixture/natural gas co-firing fuel with a sulfur absorption additive, (4) the development of a coal-water mixture fuel containing sulfur captor compounds, and (5) the assessment, retrofit and operation of a gas-fired utility boiler using a coal-water mixture fuel.

Six of the eight projects proposed in this category have been initiated in some form. One has developed to the point where the next step is commercial demonstration; the others range from bench scale to proof-of-concept projects. All projects, with the exception of one, were applicable to the industrial sector. The one exception entailed a retrofit to a utility gas-fired boiler.

None of the submitters, with the exception of one proprietary proposal, directly addressed justification for federal incentives. Where the type of incentive was described, it was either a direct financial award or an award in combination with a federal loan.

Gas Stream Cleanup

Two gas stream cleanup projects were submitted. One of the submissions proposed a method for inbed desulfurization within a coal gasifier using mixed metal oxide sorbents. Federal financing, involving direct funding, was requested for the entire development process, from basic research through pilot demonstration.

The second project cannot be discussed or described since the submitter declared the entire proposal to be proprietary.

Surface Coal Gasification

Surface coal gasification was the core technology in 27 submissions. The projects were subsequently divided into three groups -- utility systems, industrial/residential systems, and special applications -- based on the major application of the technology.

Utility Systems -- The 11 submissions that would apply to the utility sector ranged from the development of a thermodynamic model for coal gasification to the commercial demonstration of integrated gasification combined cycle systems at scales of 5 to 400 MWe.

Many of the integrated gasification combined cycle projects specified technology similar to that currently being demonstrated at the Cool Water project in California. One project, however, proposed the eventual replacement of conventional combined cycle technology with advanced gas turbines. Gasifiers included slagging fixed bed systems, fluid bed systems, and entrained flow systems. Gas cleanup systems ranged from conventional cyclones and wet scrubbers to one advanced in-bed desulfurization and hot particulate removal system.

All of the submissions sought direct federal funding support for capital costs and in some cases operating costs. Two principal reasons for this assistance were cited: (1) the significant risks entailed in recovering project costs in later years due to the heavy dependence on projected fuel price differentials; and (2) the substantial cost of gasification/combined cycle equipment which cannot be financed by the usual private utility means due to its novelty and the lack of evidence that the technology is practical and economical.

Industrial/Residential Systems -- Nine submissions were received for either the demonstration of gasifiers applied to small to intermediate size industrial/residential applications, or for coal-based concepts for producing chemicals and synthetic natural gas. Proposed projects ranged from a small (3.75 ton per day) pilot plant to a near commercial size (1648 ton per day) advanced gasification system. Federal incentives were advocated by the submitters due principally to the lower level of technical maturity and higher degree of risk associated with the gasifiers in this group.

Special Applications -- Seven projects proposed in this category could be further divided into two more specific categories:

(1) five proposed projects to convert coal to coproducts in addition to, or as a preparatory step to, the production of synthetic gas. Such coproducts include metallurgical grade coke as well as product chars with significantly better properties (lower sulfur and ash and higher heating value) than the original coal. Facilities in this category ranged in size from small laboratory research units to a 1000-ton per day demonstration plant. One project in this category requested a price guarantee and loan guarantee, while the others asked for direct federal funding.

(2) two submissions proposed advanced iron-making techniques that would use coal gasification technology as part of the process. According to the submitters, direct federal funding would be required for the projects, each of which would produce 300,000 tons per year of high purity iron for steelmaking.

Fuel Cells

Eight submissions were placed in the fuel cells category, seven of which proposed the use of the phosphoric acid technology (the other suggested an advanced molten carbonate concept).

Three submissions proposed to link a fuel cell with existing gasifiers at either the Cool Water, Tennessee Valley Authority, or Twin Cities projects, although none of the submissions showed a way in which true integration could be accomplished with an existing gasifier. Two submissions proposed a grass-roots design. Five of the submissions would rely on conventional gas cleanup techniques, one left the gas cleanup and system integration issues to be determined, and one did not address gas cleanup at all. All but one of the projects would be applied to utility power generation; the one exception would produce dc power for a chlorine/sodium hydroxide plant. All included direct federal funding, and in addition several proposed the use of government facilities and price guarantees for the product energy.

Heat Engines

While several submissions were received that included heat engine technology as part of the overall energy system, 13 submissions could be categorized as specifically focusing on the heat engine hardware.

Seven submissions would substitute coal fuels for distillate fuels in locomotive propulsion. Concepts included dry powdered coal or coal-slurry fueled gas turbines (two), a coal-derived gas-fueled turbine or diesel, a hybrid steam-diesel concept, an advanced fluid bed combustor/boiler combined with a steam turbine-electric drive, and an advanced fluidized bed boiler to drive a steam reciprocating cycle. One of the coal-slurry fuel gas turbine proposals also included a slurry fuels diesel engine as an option.

Three submissions were assigned to the category of industrial cogeneration, i.e. they would generate both process heat and electricity simultaneously. One would employ a coal-fired gas turbine, one a coal-fired fluid bed combustor, and one an air-blown gasifier, hot gas cleanup system, a diesel engine and a heat recovery boiler.

Three submissions were assigned to the Combined Cycle Power Generation Systems subcategory. All involve gas turbine component development for subsequent integration with coal gasifiers. One of the submissions was essentially a research and development effort. The other two proposed modifications to enhance efficiency and improved environmental performance.

Federal support was requested primarily in the form of direct funding although in one case a loan guarantee was proposed. Federal subsidies were judged to be necessary by those submitters assigned to the Locomotive Propulsion Systems subcategory because both railroad operators and locomotive manufacturers are reluctant to begin expensive research and development projects without reasonable expectations of commensurate payback in the near term. Federal support, according to the submitters, could result in initial testing of coal-fired locomotives within 3-1/2 to six years from the start of development, as compared to the end of the century if there was no federal involvement.

The submitters' justification for federal incentives in both the Cogeneration Systems and Combined Cycle Power Generation Systems were based generally on the relatively high initial development costs compared to long-term payback uncertainties.

Magnetohydrodynamics

Two submissions were received for retrofits of the magnetohydrodynamics (MHD) technology to the existing Montana Power Company's Bird plant. Both proposed projects would be contingent upon continuation of proof-of-concept testing by the Department of Energy, and both include the Bird plant as part of the private sector's cost sharing (although the estimated value of the plant varies by more than 100 percent depending upon the submission). The addition of the MHD topping cycle to the existing facility would increase its power output from 66 MWe to 88.6 MWe.

The federal incentive requested was direct funding at levels of about 50 percent when the submitter is given credit for the candidate base power plant and assuming that continued federal support is provided for the ongoing MHD program. This amounts to a 75 to 80 percent federal share of the direct out-of-pocket expenses. The submitters cited the high-risk, long-range nature of the MHD advanced power development effort.

Coal Liquefaction

Five submissions were received in this category. Two described exploratory bench scale research efforts. One was an informational letter documenting the submitter's ongoing interest in coal liquefaction and encouraging the Department to recognize out-year needs for pilot plant testing of new concepts. Two submissions addressed the co-production of electric power and methanol from coal using the Tennessee Valley Authority's Coal-to-Ammonia facility at Muscle Shoals, Alabama.

Direct federal funding was the preferred government incentive with cost-sharing described in only one of the submissions, the TVA-proposed "once-through" methanol synthesis project at Muscle Shoals. Federal involvement was necessary, according to the submission, to reduce uncertainties associated with the scale up to commercial size, construction and operating costs, and market potential for the methanol synthesis technology.

Underground Coal Gasification

Four submissions involved underground coal gasification. Each represented a totally separate technology or concept. One was a letter of interest from a firm proposing to undertake several risk reduction research studies. One submission suggested government funding for a research and development program to use unmineable coal as a sacrificial energy source to retort oil shale in place. A third proposal was for a cost-shared commercial plant to produce synthetic gas for a Wyoming power plant. The fourth proposed project was for a pilot and demonstration effort of underground gasification in a steeply dipping anthracite seam in Pennsylvania.

Where included, the justification for federal involvement was generally to reduce risks to sufficient levels to attract private capital.

THE ISSUE OF FEDERAL INCENTIVES TO ACCELERATE COMMERCIAL AVAILABILITY

The Congress also requested the Department, through Section 321, to identify the extent to which federal incentives might accelerate the commercial availability of emerging clean coal technologies. After analyzing the submissions, the Department concluded that federal incentives will not accelerate commercialization of these technologies and may, in fact, be counterproductive to their development.

The majority of submissions expressed a need for federal financial assistance, mostly in the form of direct funding. However, several of the emerging technical options addressed in the submissions are currently being developed at near-commercial or commercial scale without federal funds.

It should also be noted that cost sharing offered by the proposers varied significantly, not only in terms of the total amount but also in the nature of the cost sharing. For example, some proposers offered the amount of previous expenditures as "cost sharing" in return for 100 percent federal financing of future costs. Others offered to share all future costs. In many cases, cost sharing statements were not provided or were incomplete.

It should also be expected that several firms would opt for federal funds, if they were available, and some of these firms could conceivably delay the implementation of privately-financed development efforts while waiting for federal financing to materialize. The possibility also exists that some proposers who might have proceeded on their own would wait until they see which technology is backed by the government, then decide if they can effectively compete against a federally subsidized effort.

Some technologies that may not appear to be advancing rapidly to commercial scale may be hindered by valid technological or economic reasons, and therefore, may require additional research and development before they are commercially viable.

Other technologies may simply never be competitive, and the inability of these technologies to attract sufficient private sector investment may reflect investors' sound judgments as to their ultimate potential. Federal financing in these cases would not be productive regardless of the amount.

In some cases, the pace of commercial development and deployment may not hinge as much on technological issues as on the uncertainty of market demand or the uncertainty of future emission regulations that could spur demand for clean coal technologies.

Given the size and availability of U.S. coal reserves, the security of the domestic coal supply, and the comparative economics of coal as a fuel, free market forces are operating to select and commercialize the most efficient and environmentally-effective clean coal technologies. Federal subsidies could alter these market forces and adversely affect the development of competing technologies both within and outside the coal industry.

These conclusions are based on the Department's previous experiences with federal incentives. Commercial or near-commercial scale projects selected to receive assistance under prior incentive programs have been largely unsuccessful in commercializing new fossil technologies. Moreover, their lack of success has, in all probability, compounded the problems associated with the introduction of new technology. It is quite likely that related private sector projects have not been initiated because of the perceived competitive disadvantage of competing against a federally subsidized effort.

We are in wholehearted agreement with the objective of increasing the use of American coal in an environmentally acceptable manner. We believe that the government has a legitimate research role to improve coal technologies. The Administration's research program has been designed to bring about a more economical, cleaner technology for coal that will benefit the domestic coal market as well as the environment and economy in general.

Accordingly, the Department recommends to the Congress that no federal financial incentives be provided for the demonstration and commercial development of emerging clean coal technologies. Rather, the Department should continue to channel its resources into the highly productive areas of more generic coal technology research and development.

BENEFITS OF THE CLEAN COAL SOLICITATION EFFORT

Even though we recommend no future federal funding for the projects described in the submissions, significant value has already resulted from the process of soliciting statements of interest and informational proposals.

For many energy companies, the exercise was used as an organizing point to bring equipment manufacturers, architect-engineers, and other related firms into project teams. Should some of the projects proceed, many will incorporate the expertise of research, manufacturing, consuming and marketing interests within the same project framework, due to the information exchange that took place during this effort.

Information exchange between the private sector and the government was also an especially valuable product of this effort. A better indication now exists of the direction the coal and coal-related industries would like to take in the development and application of new technology. In addition, several interesting ideas emerged that may be of value to future planning of the government's coal research and development program.

This concludes my formal testimony, Mr. Chairman. I will be pleased to answer any questions you or Members of the Subcommittee may have.

Mr. FUQUA. Thank you. And before we proceed, without objection, permission will be granted retroactively to take photographs and make recordings and videos during the course of this hearing.

We also have a statement for the record by Congresswoman Lloyd and also Ms. Kaptur, who is not a member of the committee, but a Member of the Congress from Ohio.

[The prepared statements of Mrs. Lloyd and Ms. Kaptur follow:]

HON. MARILYN LLOYD
STATEMENT FOR THE RECORD
Hearing on the DOE Report on Emerging Clean Coal Technologies
May 8, 1985

Mr. Chairman and Members of the Subcommittee, I appreciate the opportunity to provide my views on this hearing topic. I also believe that this hearing is both timely and important. The subject of accelerating technology integration and development by cost-shared government demonstrations of clean coal technologies is critical. In recent years we on the Committee have seen the budgets for civilian energy research and development decline drastically, bringing some of these important R&D programs to termination and others to a barely viable level of research activity. Together with the constant reductions in the civilian research and development budgets, including fossil energy base technology efforts, the Administration has also implemented a moratorium on government-funded technology development at any meaningful scale placing the entire burden for pilot-plant or semi-works demonstration projects on the private sector.

The private sector has responded to this challenge by coming forth with a multitude of high quality proposals in response to the recent Administration solicitation for cost-shared demonstration proposals. (This recent solicitation was admittedly in response to a Congressional mandate.) From the published responses to the DOE solicitation in the November 27, 1984 Federal Register, it is apparent that the private sector is keenly interested in the development of clean coal technologies but cannot make the large financial commitment necessary to definitively prove the feasibility of these emerging technologies.

The recently published Department of Energy report to the Congress on Emerging Clean Coal Technologies contains the stunning statement that "Federal incentives will not accelerate commercialization of the technologies and will be counterproductive to their development." How the DOE can substantiate this sweeping conclusion is beyond any knowledgeable observers of coal R&D. The statement is based on the Department's a priori conclusion that only free market forces should be allowed to work in the selection of the most appropriate advanced technologies for coal use. I am aware of one project which involves significant EPRI funding, the Atmospheric Fluidized Bed Combustion (AFBC) project being developed jointly with TVA, DOE and the Commonwealth of Kentucky in Paducah, Kentucky. However, I am at a loss to name a specific technology presently being readied for commercialization at the same scale without federal funding. I would also remind my colleagues on the Committee that while "soft" oil prices and temporary "gluts" buy us time, they should nevertheless provide even stronger incentives for federal involvement.

Curiously, while the Department does not recommend that federal funds be used for demonstration, it does recommend that the DOE channel its resources into, or "concentrate on", coal R&D. What appears paradoxical here is that when we take a look at the DOE budget request for the past few years for fossil R&D, we see that it has steadily declined under OMB pressure.

In direct contrast to DOE's stated position and optimistic, yet unfounded, belief in free market forces, the report contains a project proposers' list of the needs for federal assistance to bring their projects to commercialization. The most common justifications for federal assistance were listed as follows: (1) the private sector does not have the required resources; (2) the proposed projects are high technological risks, and (3) federal support is required for commercialization of processes that address a national need. It appears that the private sector does, indeed, take a quite different view of commercialization than the Department. It is also evident from the lack of new commercial clean coal technologies entering the marketplace, that federal incentives are necessary.

Ironically, the DOE's own Energy Research Advisory Board (ERAB) panel report makes a strong case for federal involvement in commercializing technologies when the ultimate user cost-shares the project on at least a 50% basis. The panel, in fact, concludes that the current policy of no federal funding for commercialization should be changed. The concensus was that the absence of federal involvement past the proof-of-concept stage has resulted in abandonment of promising technologies because of the significant risks attendant to scaling-up, integrating large systems, etc. A federal role in these cases would have been anything but "counterproductive."

Another problem described in the ERAB report was the Department of Energy's rather poor track record in sustaining its contractual obligations with the private sector. This was a common concern of our private sector witnesses during the ERP subcommittee hearings on the FY 1986 DOE authorization. The outside witnesses expressed their frustration at the "sometime" partnership they encountered with the Department and the disruptive influence on their research efforts of uneven financial support for the projects.

I believe it is even more important to provide some government funding for demonstration projects in light of the recently released Office of Technology Assessment (OTA) report on offshore oil and gas reserves. The OTA report concludes that the 1981 Department of Interior estimates of offshore oil and gas reserves were over-stated by a wide margin. Recent explorations have been disappointing in terms of discovery of additional reserves. Also, the costly development of some of these reserves is a factor to be considered when we attempt to plan for our future energy security. To have the "supply-oriented" Administration announce these pessimistic prospects is compelling evidence to dispel the illusions cast by today's "glut" and "soft" prices.

I understand that the Department is under some contraints imposed on it by the Office of Management and Budget (OMB) regarding any implementation of the Congressional directive to fund clean coal technology demonstration projects. Unfortunately, the Department's lack of interest in fulfilling the spirit of Congressional mandate is so great that relative technical assessments and any ranking of the projects are completely lacking. I am disappointed with the quality of this first effort and hope to see much improvement in the DOE's promised supplemental assessment. I would hope that the enthusiasm shown in the private sector's response will be sustained at a high level until the Department chooses to implement the spirit of the Congressional mandate.

In order to work around inadequacies and inconsistencies in Departmental policy, I would like to recommend two courses of action which I believe would give the Department more certain guidance for developing clean coal research programs. This is the type of policy directive which the Congress itself has attempted to provide for the past several years. My first proposal is to transfer some additional funds from the SFC Energy Security Reserve fund and provide it to the Department of Energy for use in complementary projects for clean coal technology development including small coal conversion pilot plants. This money would be a supplement to any other funding authorized for fossil R&D for use by the Department. The beleaguered Synthetic Fuels Corporation still has $7.9 billion remaining in already appropriated monies, but I'm afraid that it is very likely that some of this funding will never be utilized for its intended purpose. The changing public perception and unfortunate perceived lack of urgency with respect to our national energy needs are all part of the changing climate for the federal development of synfuels in the private sector and in the Congress. These factors, albeit regrettable, are pointing toward a further reduction in the SFC's already reduced resource base even though there is a mix of projects before the Corporation which merit some funding. It thus makes sense to me to redirect up to $1 billion in funding into the companion clean coal technology development and demonstration program now before us in the likely event that the SFC certainly will not commit the entire $7.9 billion.

I do plan to introduce a modified version of my Clean Coal Technology Development and Utilization Act, a bill which I originally proposed in the 98th Congress. In fact, the proposal I just outlined, which is similar to the transfer provisions of the earlier version, will be included in the updated version of the bill.

My second proposal deals with the $750 million provided for clean coal technology development in last year's continuing resolution on Interior Appropriations. I suggest that our Committee take a positive approach by passing a generic authorization bill which would delineate the categories of projects which should be funded by the Department and provide some carefully crafted yet broad guidelines for their implementation. In the past I have taken the position that it is inappropriate to micromanage the Department and I still believe that. However, realizing that we have limited resources, I think that a cautious, cost-shared development plan between the Department of Energy and the industrial performers will be money well-spent for our energy future. I also believe that we should not abrogate our responsibility as an authorizing committee to appropriations. If the Congress must act because DOE refuses to come forward with criteria for project selection in terms of technological maturity, etc., we should "bite the bullet."

Finally, I would like to comment on the demonstration of emerging clean coal technologies within the context of acid precipitation. I have been an outspoken advocate of the need to intensify our research effort into cause-effect relationships in "acid rain" chemistry. Therefore, it is reassuring that the request for this research program received a substantial increase in FY 1986; it is still the sole avenue to any reasonable cost/benefits analysis.

In concert with this focused acid rain research program, I believe we also need to continue our work on developing clean coal technologies and bringing them into the marketplace. Whether our research results show that sulfur dioxide is determined to be the major factor in acid precipitation or not, we do need to utilize this important natural resource in an environmentally sound manner. This relatively small investment in our energy future will surely serve as an insurance policy for a healthy future energy supply.

We have the opportunity to lay out a DOE clean coal technology program which complements a limited SFC program on diverse synfuel technologies. We must ignore the illusory supply circumstances which obscure our long-term liquid fuels problem. We are running out of gas and oil and we must burn coal cleanly to complement nuclear energy for a balanced supply of both electricity and related industrial process heat.

It would require an extended discussion to adequately document the difficulties which have faced the synfuels programs in the SFC, but two points are worth stating: First, the Administration's ambivalency and ineptitude in handling SFC matters, aggravated by Congressional obstructionism and meddling on the part of SFC opponents, have diverted industry resources which might have better been devoted elsewhere. This is particularly true in the unproductive case where the Corporation withdrew solicitations after project teams were already hard at work and considerable efforts were made in developing proposals and supporting activities to refine designs. Secondly, although in this deficit climate it is particularly easy for Members to support the "sham cut" in the Energy Security Reserve (since virtually no outlays are involved), we cannot wish away our long-term liquid fuels problems. We have not even achieved technical confidence in converting coal to oil and gas at significant scale, no less improved the economics of these schemes. Since lead times of interest are certainly a decade or more for these technologies, we can now project our synfuels uncertainty into the end of the next decade. We simply must identify the most promising conversion processes now so that we can have clean coal technologies by the late nineties because the oil and gas route will become a "dead end" early in the next century.

STATEMENT OF

THE HONORABLE MARCY KAPTUR

TO

THE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS

COMMITTEE ON SCIENCE AND TECHNOLOGY

U.S. HOUSE OF REPRESENTATIVES

MAY 8, 1985

MARCY KAPTUR
MEMBER
9TH DISTRICT, OHIO

COMMITTEES
BANKING, FINANCE AND
URBAN AFFAIRS
VETERANS' AFFAIRS

1228 LONGWORTH BUILDING
WASHINGTON, DC 20515
(202) 225-4146

FEDERAL BUILDING
234 SUMMIT ST., ROOM 719
TOLEDO, OH 43604
(419) 259-7500

Congress of the United States
House of Representatives
Washington, DC 20515

Mr. Chairman, thank you for allowing me to address the Subcommittee today to express my support for Clean Coal Technology.

In 1984, Congress wisely recognized the need to support demonstration of those Clean Coal Technologies near commercialization. In doing so, we realized that certain short-term economic forces operated against the introduction of new alternative cost effective energy technologies into the marketplace. Specifically: (1) our current over dependency on oil and natural gas (2) the glut of oil on the world market (3) depressed crude oil prices and (4) the environmental problems associated with the burning of fossil fuels.

The realities of the situation were obvious. Imports now account for roughly one-third of all of the oil we use, just as they did before the Arab oil embargo of 1973. United States' consumers spend $57 billion annually on foreign petroleum products. In New England and the Mid-Atlantic states, one-half of total energy consumption still comes from oil. In my state of Ohio, 94% of the oil consumed in 1983 was imported into the state. That our trade deficit is at historically record levels is quite well known. Further, there isn't one of us that can forget the political, economic and strategic effects of being caught "over the barrel" in oil embargoes in 1973 and 1979.

Congress has debated the difficult solutions to the enviromental problems associated with the burning of fossil fuels for a number of years. For those of us who represent the Northeast-Midwest, the problem of acid rain has long been debated with no resolution in sight. No existing technology of lower emissions from industrial areas, or any attempt to arrive at a solution through regulation, has met with widespread support. Clearly, another approach may have to be taken.

I believe strongly that Clean Coal Technologies can be that new approach.

Coal represents America's most abundant energy resource and is a key to achieving greater self-sufficiency. Some would rename the coal belt that lies between Pennsylvania, Ohio, West Virginia, Kentucky, Illinois, Indiana, Energy Valley U.S.A. The Northeast/Midwest region's demonstrated reserve base contains enough coal for 750 years of consumption at 1982 levels. In fact just these states have as much coal energy in Btu's as the entire Middle East on which this nation has become so dependent. The only difference between the Btu's we have underground in the U.S. compared to the Middle East, Saudi Arabia, or Kuwait, etc. is that our Btu's are in solid form and theirs are liquid. In my state of Ohio, 38% of our total energy consumption and 95% of our electric utility consumption came from coal in 1981. We expect that level to increase, both in Ohio and throughout the United States. By increasing our reliance on coal, we can decrease our dependence on the imported oil that once held us hostage. We can improve our trade imbalance. We can provide jobs and investment that will invigorate our economy. Coal is still a cheaper fuel than its alternatives, even with the cost of control technologies added. Therefore, as consumers, we all benefit.

The real challenge in building a coal-based energy system in the United States may rest with Congress. In order to burn coal in our industries and homes tomorrow, we must learn how to burn it cleanly today. 175 submissions of interest on Clean Coal Technology have been received by the Department of Energy. These submissions would seem to indicate that coal can be burned cleanly. We owe it to ourselves and the nation to find out. Although there may be disagreement over the present acid rain problem, there is little disagreement that effective action must be taken immediately.

Clean coal technologies can correct problems arising from the direct burning of coal and improve the process of conversion and use of coal into gaseous or liquid forms. Clean coal technology can effectively deal with the problem of acid rain. For example, an Ohio firm, Calderon Automation, has submitted a proposal to DOE to convert coal into gaseous and liquid forms with no environmentally hazardous by-products. An assessment of this plan by the Bechtel Corporation stated that the Calderon process is technically feasible and economically sound.

Clean coal technology is needed, but must be researched further and brought to commercialization. The potential impact on our nation's economy is great. In my own state of Ohio, where we have a huge reserve of high-sulfur coal, Clean Coal Technologies would mean jobs and renewed industrial growth. However, given the current oil glut and the environmental problems associated with coal, this crucial research and commercialization needs to be encouraged by the federal government. With the acceptance and support of a Clean Coal Technologies program, proposals such as the Calderon Process for a clean coal-based economy can bring us the benefits of a stronger economy and a healthier environment. The Congress acknowledged these facts last year by authorizing these funds. Mr. Chairman, members of the Subcommittee, I thank you in advance for your support of Clean Coal Technologies.

Mr. FUQUA. Bill, in your statement, in your formal statement, you are referring to the report and to the environmental promise, cost, stage of development and scientific feasibility of some of the technologies, and you said this will be submitted to Congress. Is there any indication when we might expect that report?

Mr. VAUGHAN. I don't have a good idea quite yet, Mr. Chairman. I believe it will take some months, however, to do a comprehensive monograph-type inquiry using all these sources.

Mr. FUQUA. Is DOE going to do this in-house with your own employees, or do you plan to contract that out or hire consultants to do that?

Mr. VAUGHAN. I believe, Mr. Chairman, that this particular further report, and this is my personal opinion, can best be done by an outside activity rather than inside personnel, one, for practical reasons. We do have ongoing programs and we need to have these 50 people that were involved in this effort back in their mainline jobs, and I simply feel that we cannot afford this additional activity on their part. And second, I believe that those 50 scientists and engineers gave this a very good shot, and that the most advantageous stance now would be to have as objective and out-of-the-fray look at the problem, as distant a look at the problem, as we can get. Of course, we are actors in this process ourselves, and we think that having a report done by an outside activity would be more useful.

Mr. FUQUA. But you haven't engaged anyone yet or signed any contracts——

Mr. VAUGHAN. No, we have not, Mr. Chairman.

Mr. FUQUA [continuing]. Or set a timetable, then?

Mr. VAUGHAN. In fact, we haven't really decided—it may well be that the most effective format is a grant rather than a contract, so that it truly is independent.

Mr. FUQUA. When you reach a decision about the timing of the report, could you notify the committee so we might have a timetable of expectation, so that we could discuss it.

Mr. VAUGHAN. Yes, Mr. Chairman, I will be more than happy to when we make decisions on this matter. I think it would be appropriate to draft a letter to the committee and inform you of the way we think we should do it, and the timeframe that we have in mind.

Mr. FUQUA. Thank you. The report to DOE states that DOE is unable to judge which of the emerging technologies is most likely to be accepted for extensive future use by industry. Now, it would seem that the issue is not of acceptance, which is an industry decision, but rather of technical readiness so that the industry can make that decision.

In that context, is it the position of DOE to judge the future as to when emerging technology will have completed development necessary for an industry decision?

Mr. VAUGHAN. If I understand your question, Mr. Chairman, as we try to put together the role as we see it in R&D, we are trying to do the things that are long range, high risk generic, and which we see that industry either is unwilling or unable to do itself. If we find a promising idea that industry is doing on its own, we very consciously do not put the Government into the same activity.

What we are talking about in the context of this report in general is not R&D. If you recall, this report specifically sought out suggestions and ideas for demonstration projects. That is, really, the step of taking financial risk, to take technologies that have been brought through the technological question stage; that is, through the proof-of-concept portal, and carry them to the market.

Mr. FUQUA. Let me maybe clarify what I'm talking about. Depending on the financial risk that someone is willing to take, would that influence you or do you determine where the technology is going to be? If someone comes in and wants to fund 75 percent of it, another comes in and says, "Well, we want you to fund 75 percent," would that give you an indication how much confidence they had in their technology?

Mr. VAUGHAN. In general, that does give one an indication of how confident the proposer or submitter is in his own work. He is seeking to have, in general, minimum Government involvement so that he has maximum latitude to move on and make his profits out of the exercise. And then when you have a high cost participation recommended that usually indicates that the proposer or submitter is quite confident in the technology.

Mr. FUQUA. So DOE would not try to judge, necessarily, emerging technology that has completed the development stage, but let that be an industry decision?

Mr. VAUGHAN. Absolutely, Mr. Chairman.

Mr. FUQUA. Let the market forces.

Mr. VAUGHAN. Absolutely. We have no interest and, really, we think we have no proper role in making that kind of risk decision for industry. And we think in the past when we have gotten in that role we have been rather singularly unsuccessful in moving projects forward. The Government's ability to make that kind of decision based on the track record has not been a very good one.

Mr. FUQUA. Well, let me compliment you on that position.

There is also widespread reports that the Secretary has offered to prioritize the "Emerging Coal Technologies" report, and I'm trying to understand what does the term "prioritize" mean. Does it refer to technology or letter of intent, or both? And when will this be done? Who will perform the activity? And what value do you place on the results of it?

Mr. VAUGHAN. I, frankly, cannot tell you precisely what the Secretary meant in that dialog. I do know that he made very clear to me what he did not mean, and he did not mean that he would rank order these 176 proposals as item 1, 2, on through 176. He made that very clear that is not what he had intended. He was hopeful that we would be able to rank technologies or prioritize technologies. He is now more mindful of the fact that that is really an extraordinarily difficult chore and, at best, has limited utility. Because it's ranking or prioritizing technologies for what purpose?

We give an example. If you are looking for something to be used by utilities, one approach might well on balance, look to be most promising. On the other hand, something to be used in the transportation sector may be a totally different technology. You will have different sets of criteria for different end uses for different environmental needs and those sorts of things; and even, perhaps, for different coals.

Mr. FUQUA. Well, that was my next follow-up question. Would it involve the different regional-type sources of coal? Or would that be prioritized?

Mr. VAUGHAN. That is a factor. I think, though, it is hard in a priorities sense. I think prioritize, perhaps, has the wrong connotation because that might lead one to think that Eastern coal is more desirable than Western coal.

Well, ask for what purpose? You have high and low sulfur coals, you have high and low Btu content, high and low moisture and ash content—these are the things that really make the difference. You also have distance from mine, cost factors such as hauling and so on. So, it seems to me that one must be very careful in an attempt to prioritize technologies. I think that is, frankly, an exercise that our predecessors attempted without a lot of success. Attempted to decide that gasification is inherently better than liquefaction, and I am not sure that that is a supportable conclusion. Better for what purpose under what circumstances.

I think what we are trying to do, Mr. Chairman, is to offer the widest possible array of technological choices for coal utilization for the amount of funds that we feel we can afford to put to this use. And so thus, we have set up some criteria such as if we know that a company is proceeding with the technology and it looks like they are doing fine, then we are happy with that and we don't attempt to compete with them. Let them do it. We will go use those funds somewhere else.

Clearly, if we are going to work with industry, we like the concept of cost sharing, because we get to leverage those dollars. I think I also, before this very committee, have a number of times indicated that I think cost sharing should continue all the way through the project. Unfortunately, in the former years, the tendency was for there to be massive Federal funding available. There was talk about cost sharing but the cost sharing came late in the process. If the process ran into technological or economic difficulty, somehow the private dollars were never put up. It seems to us that we should learn from those lessons of the past, and we are proposing to.

Mr. FUQUA. Let me commend you. I think your approach appears to be a commendable one, and I hope the forces at DOE and OMB let you follow through in that fashion.

Mr. Boucher.

Mr. BOUCHER. Thank you, Mr. Chairman.

At the outset, I want to commend the chair for holding this very timely hearing on what I think is a very important subject. I want to thank Secretary Vaughan for joining us here today.

Secretary Vaughan, I can't say that I was entirely surprised, but I was somewhat disappointed at the conclusion reached in your report that the Government should not participate at this time in cost sharing for the construction of demonstration-scale projects. It seems to me that that conclusion is squarely in conflict with the report that DOE requested and recently received from the Energy Research Advisory Board, which finds that the emerging clean coal technologies are not going to be promoted through the commercialization stage, through the demonstration stage, in the absence of some assistance from the Government. As a matter of fact that report concludes that there is a very real role for DOE to play in assisting with the construction of demonstration-scale projects, and that the abandoning of these projects after the proof-of-concept stage is going to result in exactly that, in their words, "abandonment of the project." And I think that has been the history.

In light of that recommendation which DOE requested from the Energy Research Advisory Board, why have you reached your conclusion? Do you just flatly disagree with the Advisory Board's recommendation made to your Department?

Mr. VAUGHAN. Well, first, Mr. Boucher, I don't believe we have formally received that report, although I have read the two drafts of the report and I think I certainly am aware of its thrust in its basic conclusions. In fact, I am very much aware of those. I think you have, perhaps, characterized the thrust of the report fairly accurately. I would point out, however, that the report—I would characterize that report as saying, first, it concentrates on utility use of coal; secondly, it concentrates on doing that very rapidly, or at an accelerated pace; and then it reaches the conclusion that in order to do accelerated coal utilization in utilities it will be necessary, in the ERAB panel's opinion, to have Federal Government involvement in the demonstration and development phases.

Now, if that is one's mission; that is, to see that utilities use coal at a much more accelerated rate, then I think perhaps the conclusions of the ERAB report would be indeed hard to argue with. In fact, I take no basic argument with the report itself. I think this administration, however, has defined its role in a number of energy areas in a significantly different manner. It has seen its role as trying to make it technologically possible for our private sector, including utilities and equipment manufacturers, coal producers, and others, to make decisions and move forward as they see fit. We do not see that it is necessary to use taxpayer funds in this process.

I do not think that we would argue that certainly the process may be slower. I think that is brought about by several factors. The first is we believe fundamentally that the government should not be making these kinds of entrepreneurial risk-type decisions, and clearly, in my judgment, the decision to fund a particular project on a cost basis, any kind of cost basis, will grant to that particular technology or project a competitive advantage and a real leg up. Undoubtedly, it will move it faster, but what one needs to ask is what about the situation we are, in fact, in? That is, limited funds and a need to make those funds go as far as possible and to offer as many choices as possible to the public at large. I think that is the essential area of disagreement.

Now, ERAB I think very forthrightly calls into question that policy difference and asks us to reconsider it. The Secretary asked for that report in good faith, and I think I can assure you that he will consider it in good faith. But he does, along with the rest of us in the administration, have to balance a number of factors. So I will not promise you, because I, frankly, do not know how he will come out of that balancing process.

Mr. BOUCHER. Well, I am delighted to hear you say that the ERAB report is going to be fairly and objectively evaluated in due course by the Department, and I, for one, hope that in view of its clear recommendations, which are in conflict with the recommendations that your report contains, that some amendment to your recommendations will be forthcoming.

I noticed a statement that you made during your response to the chairman's question. That the Department should not be placed in the position of competing with private concerns that are in the process of constructing demonstration-scale facilities for emerging clean coal technologies. I am, frankly, not aware of private concerns that are in the process of doing that. We know that atmospheric fluidized-bed combustion is being developed, but that was done almost solely at Government expense, perhaps all at Government expense. I am not aware of clean coal technologies today that are being developed purely by private industry and that are being placed in a demonstration-scale posture.

If you can enlighten me some on that and point to some areas where the Government would be competing, I would very much like to hear it.

Mr. VAUGHAN. Well, let me just, Mr. Boucher, go to the report itself. I mean our report, now, and the submissions we received because we did receive several indications in that effort alone of such activity. Southwest Public Service, a utility, asks only that we assist in achieving regulatory changes with the EPA. It very specifically did not ask for any fund sharing, not one dime.

Mr. BOUCHER. What kind of project were they proposing?

Mr. VAUGHAN. It was a lime injection—LIMB project.

Southwestern Public Service, the same company, in an AFB proposal asked for, if I recall, $700,000 out of a $100 million project. That is very close to asking for little to no funding, and it is hard for me to believe that at the funding level they were discussing the absence of the $700,000 will spell life or death.

Mr. BOUCHER. What kind of project was that?

Mr. VAUGHAN. That was an AFB project—atmospheric fluidized bed.

Colorado Ute Utility currently has under construction a privately financed, as I understand it, AFB project, sought no funding. In a coal gasification process, K-fuel process, actually the company's submission was in the tone of asking us not to recommend Federal funding at the demonstration level pointing out that it had spent millions of dollars of its own and that it would consider funding of its competitors as an economic disadvantage and then saying, however, if you want to throw the taxpayers' money away we would like to be refunded for the efforts we have put forward so we will be on an even playing field.

There are several significant developments I think in coal/water fuels—to get out of the report itself—that are aggressively moving forward with essentially no Government funding. You can buy the fuel. The manufacturer will sell it to you, enter into a contract today, as I understand it. There are a number of fluidized-bed boilers under construction with no Government participation.

So, I think there are instances in which progress is being made without Government funding, and again at the demonstration scale.

Mr. BOUCHER. Well, it is encouraging to hear that that is happening, and I appreciate your supplying that information. I know that a number of proposals have been made for physical coal cleaning, precombustion, which private industry frankly feels it cannot move forward with on its own. I am not aware of any projects of that nature that are slated for purely private funding at the demonstration-scale stage. It occurs to me that these are enormously promising, and I would hope that in any supplemental report that the Department prepares that consideration would be given to cost sharing with respect to that construction.

Let me ask one final question, if I may, and that relates to information that has been received recently concerning the possible participation of the National Coal Council in working with the Department of Energy in establishing some priorities for the utilization of emerging clean coal technologies.

Is that accurate information? Is the Department actively considering that? And if so, what would the National Coal Council's role be in that effort?

Mr. **Vaughan**. As you know, we are currently underway in setting up the National Coal Council, and I am aware of the information that we may ask the National Coal Council to look into this matter. I think perhaps that is a little, stated a little simply one of the purposes, in fact, the prime purpose of setting up the National Coal Council was to have available to the Federal Government the advice of these persons asked to serve on this Council from a wide range of backgrounds and interests in coal. And among the topics that one would logically ask at some point is what does the Council think about various technologies that affect the coal industry.

There are many other topics that affect the coal industry that we would expect to ask the Council about, too. In fact, anything of interest to coal utilization is fair game. Now, the confusion I think comes in the context of this particular effort. I think that is indeed confusion. We have ourselves just filed this report. As I mentioned in my testimony the International Energy Agency's R&D arm just completed, fairly recently, a report on coal technologies, and ERAB, as we discussed here, is also completing a report, and we will be looking at those and other information and certainly I think it would be appropriate to seek some input from the National Coal Council.

However, I think what we definitely do not intend to ask the National Coal Council is how to divide up the $750 million. That is the kind of flavor that came out in the trade press, and I think I can assure you the Secretary did not have that in mind.

Mr. **Boucher**. Well, I want to commend you, Mr. Secretary, for the suggestion that the Coal Council be involved in considering the appropriate roles for the Government in funding for research and development efforts. I know that one of the companies that will be represented on your Council is very active in private R&D efforts, and I think there is some very useful advice that could be forthcoming that would significantly assist the Department.

My time has expired, Mr. Chairman. I want to thank you again, Mr. Secretary, for your interest in this subject and for being with us today.

Mr. **Vaughan**. Thank you, sir.

Mr. **Fuqua**. Mr. Brown.

Mr. **Brown**. No questions.

Mr. **Fuqua**. Mr. Fawell.

Mr. **Fawell.** No questions.

Mr. **Fuqua.** Mr. Packard.

Mr. **Packard.** Thank you, Mr. Chairman.

I am particularly excited about the renewed interest in coal and its usefulness, and the efforts being made to clean up coal to where it becomes a useful resource for us.

Mr. Secretary, the efforts in coal cleanup it would appear to me could be done in different ways. You referred to the fact that high sulfur content and high and low Btu capabilities may alter the cleanup process so that it could be cleaned up specifically designed to service a certain purpose. Would that mean that there could be different processes or ways in which we would prepare coal for a useful purpose?

Mr. **Vaughan.** Absolutely, Mr. Packard. Let me just briefly try to take you through where I think is the broad area of effort. Our research program is directed currently in three broad areas. We are doing R&D on cleaning up coal as soon as you have mined it and before you try to use it. That is generally referred to as coal preparation, and there are a number of techniques that are being seriously investigated in that area.

Then we are addressing the combustion process itself, and there you have a twofold effort. You are trying to increase efficiency so that you burn less coal for each unit of useful energy you get out of the process. And secondly, we are looking at a number of techniques as ways to improve the environmental response in the combustion process itself and, very loosely put, try to burn up the pollutants in the process itself or cause a chemical reaction to occur during the combustion process that renders an otherwise harmful pollutant inert.

And finally, we are doing work in the post-combustion phase; that is, something that you hang on the flue gas end to try to improve the environmental performance. It is in that area that the term "retrofit" is often used because the country has considerable capital stock in existing equipment that can use either the—you either put much cleaner coal into the process on the front end or you have to clean up the effluent on the back end because you are fundamentally stuck with a combustor for the rest of its service life.

And last, I think I ought to refer to yet a fourth area and I will generally refer to that as the more exotic approach, and that is to make totally new fuel forms such as coal/water mixtures, coal/oil mixtures, and perhaps even a fuel of an ultra-fine powdered coal or a mixture of partially refined coal and the chars and liquids that we can produce. In that broad category I would also include gasification. The technology there is proceeding both to gasify in place—that is, in situ, as you find the deposit—and also to mine the coal and put it in a retort for gasification purposes.

Mr. **Packard.** Is one of the primary objectives in a cleanup process to resolve the acid rain problem?

Mr. **Vaughan.** It is certainly one of the primary objectives; yes, sir.

Mr. **Packard.** In the R&D work that is being done on coal, what are the tax incentives or the other incentives? In some resources there are depletion allowances, there are research or exploration benefits; are there any such benefits in encouraging the research and development of coal use cleanup process?

Mr. VAUGHAN. Congressman, I do not believe that there are any special tax incentives for coal R&D on the books today that are above and beyond the usual tax expensing or cost of R&D for any purpose.

Mr. PACKARD. Has there been any analyses to equate the research and development of coal in relation to other either energy or resource needs of the country?

Mr. VAUGHAN. If I understand your question correctly, Congressman, you are asking me have we investigated the relative role of coal and promise of coal among our energy resources, and if that is the thrust of your question, yes, we have rather extensively.

Mr. PACKARD. I am talking now about an analysis of the tax incentives or other incentives tied with other products in relation to coal, or are we treating some resources, oil and forests and so forth, taxwise differently than we are coal, and does that render coal and those who research coal in terms of cleanup process, at a disadvantage businesswise?

I may be asking questions that are not within your purview, I am aware of that. But I am interested in knowing if there are incentives or if there could or should be incentives that equate to oil and other energy materials.

Mr. VAUGHAN. I, frankly, Congressman, am not sufficiently informed on the tax aspects to really fully answer your question. May I take that question for the record——

Mr. PACKARD. If you have someone on your staff that could provide that for the record, I would appreciate it.

Mr. VAUGHAN [continuing]. And consult with my colleagues over in Treasury and other parts of the Government and give you a comprehensive answer?

[The material referred to above follows:]

TAX INCENTIVES RELATED TO COAL R&D

We are not aware of any in-depth investigation done by DOE that compares existing tax incentives related to coal R&D and incentives for other energy resources. However, it is our belief that existing incentives are such that rational, market-driven decisions are being made with regard to funding coal R&D. Special incentives or vehicles oriented toward R&D include the 25 percent tax credit, R&D limited partnerships, and the passage of the legislation relaxing U.S. antitrust laws regarding joint R&D ventures. All of these have proven very popular and effective, and would certainly be applicable to coal-related R&D.

Mr. PACKARD. I think it would be at least of interest, if not perhaps productive, in terms of looking at the future for coal.

One last question, Mr. Chairman, if you would permit. And that is I heartily endorse the concept, and have in not only coal research but in most other areas, of the cost-sharing concept with the private sector. I also endorse the concept of repayment when our Government funds are responsible to some degree of producing a technology that is commercially marketable and that the private sector can benefit from.

Is that being considered wherein the research that the Government funds or are participating in that there is a reimbursement agreement that if and when commercialization takes place the company benefiting from such commercialization would repay Government participation in the research and development?

Mr. VAUGHAN. The answer to your question, Congressman, is that one of our prime criteria for considering proposals generally in R&D in the Fossil Energy Program is the degree and extent of cost share offered by the private sector. And that is one of our prime interests. I would point out very specifically that Congress in laying out the charge for this particular report that we are discussing here this morning laid particular emphasis on that subject, and the response is, indeed, informative; that there appears to be a fairly high degree of willingness to engage in cost share.

With respect to the reimbursement, we have used that technique on occasion, particularly where the Government portion of the funding had been proportionately quite large. And we have projects today where there is a reimbursement agreement involved. I think reimbursement agreement is quite useful, but I do think there is a trap that one can get in with respect to reimbursement agreements. The government only gets its funding back when there is success in the marketplace.

Mr. PACKARD. I think that is appropriate myself.

Mr. VAUGHAN. A number of us would question, in this administration, whether it is appropriate, particularly after one passes the R&D phase, to provide funds to a project and have as the only means of reimbursement. In that situation the company involved has little to nothing at risk, and we think that is most undesirable.

Mr. PACKARD. I would agree with that.

Thank you, Mr. Chairman.

Mr. FUQUA. Mr. Walgren.

Mr. WALGREN. Thank you, Mr. Chairman. Let me ask at the outset, Mr. Chairman, if I could introduce into the record, with the other members' consent, testimony of Congressman Dennis Eckart given before the House Appropriations Subcommittee on the Interior on behalf of the Northwest-Midwest Coalition. It is a useful statement and one that I would like to make a part of our record if I could.

Mr. FUQUA. Without objection, you can include that.

Mr. WALGREN. Thank you, Mr. Chairman.

[The prepared statement of Mr. Eckart follows:]

CONGRESSIONAL COALITION
U.S. House of Representatives

CO-CHAIRS
Howard Wolpe (MI)
Frank Horton (NY)

VICE CHAIRS
Bob Edgar (PA)
Silvio O. Conte (MA)
James L. Oberstar (MN)

TREASURER
Claudine Schneider (RI)

STEERING COMMITTEE
Berkley Bedell (IA)
Sherwood L. Boehlert (NY)
Robert A. Borski (PA)
Beverly B. Byron (MD)
Thomas R. Carper (DE)
William F. Clinger, Jr. (PA)
Thomas J. Downey (NY)
Dennis E. Eckart (OH)
Lane Evans (IL)
Edward F. Feighan (OH)
Hamilton Fish, Jr. (NY)
Frank J. Guarini (NJ)
Steve Gunderson (WI)
Lee H. Hamilton (IN)
Paul B. Henry (MI)
James M. Jeffords (VT)
Marcy Kaptur (OH)
Barbara B. Kennelly (CT)
Stan Lundine (NY)
Stewart B. McKinney (CT)
Lynn Martin (IL)
Nicholas Mavroules (MA)
Parren J. Mitchell (MD)
Barbara A. Mikulski (MD)
Jim Moody (WI)
Henry J. Nowak (NY)
Donald J. Pease (OH)
Carl D. Pursell (MI)
Thomas J. Ridge (PA)
Matthew J. Rinaldo (NJ)
John G. Rowland (CT)
Robert C. Smith (NH)
Olympia J. Snowe (ME)
Thomas J. Tauke (IA)
Bruce F. Vento (MN)
Doug Walgren (PA)
Sidney R. Yates (IL)

EXECUTIVE DIRECTOR
Laurence Zabar

TESTIMONY OF

THE HONORABLE DENNIS E. ECKART

BEFORE THE

HOUSE APPROPRIATIONS SUBCOMMITTEE ON INTERIOR

April 18, 1985

530 House Annex No. 2, Washington, D.C. 20515 • (202) 226-3920

Mr. Chairman and Members of the Committee:

As a member of the Steering Committee of the Northeast-Midwest Congressional Coalition, I welcome this opportunity to testify on the treatment of the Clean Coal Technology Reserve in the fiscal 1986 Interior Appropriations bill. My colleague, Rep. Claudine Schneider of Rhode Island, will be testifying before you on other issues in the Interior Appropriations bill of particular concern to the Coalition. The Northeast-Midwest Congressional Coalition, formed in 1976, is a bipartisan organization of nearly 200 members of the House from the 18 states of the region. We seek to inform our members of the ramifications of national policies upon the region and to influence those issues of greatest importance to the states of the Northeast and Midwest.

Earlier this year, in testimony before the House Budget Committee, the Coalition supported a freeze of budget authority for defense spending and for most domestic programs at fiscal 1985 levels. We believe that a freeze such as the one we advocate is necessary if Congress is to demonstrate its commitment to fairness and equity, and must be accepted as the first step toward creating any deficit reduction package.

At this time, I would like to address the importance of funds being appropriated in the fiscal 1986 Interior bill for the Clean Coal Technology Reserve. Last year the Congress established a $750 million Fund from the $5.4 billion rescission from the Synthetic Fuels Corporation.

The reserve was established to support cost-shared demonstrations of technologies that are near commercialization and that could burn coal cleanly and economically. The Coalition strongly urges that funds be appropriated so that at least several projects can receive funding in fiscal 1986. It is clear that substantial interest already existing in the private sector, as 175 statements of interest have been received by the Department of Energy concerning the reserve. The submissions have come from 28 states, including 14 states from the Northeast-Midwest region.

Furtherance of clean coal technologies is of special importance to the Northeast-Midwest region for several reasons:

- Coal is an abundant, indigenous energy resource and can continue to be an important energy source for the future as long as it is developed in an environmentally sensitive manner;
- The U.S. continues to import substantial amounts of oil which contributes significantly to our trade deficit: these imports potentially could be reduced through use of other alternatives such as conservation, renewables, and clean coal;
- The Energy Information Administration predicts that overall coal use will increase by nearly one-third in the next decade in both the utility and industrial sectors;
- Most of the coal in the Northeast-Midwest region has a high sulphur content, thereby raising environmental concerns about its use;
- Coal currently accounts for over half of all energy consumed by the utility sector in the U.S. and for 80 percent of the energy used by utilities in the Midwest;
- The coal mining industry has an important effect upon local employment. Nationally, coal mining employment dropped from 229,000 in 1980 to 176,000 in 1983; in the Northeast-Midwest region, employment dropped from 71,000 to 57,000;
- Clean coal technologies burn coal more efficiently, economically, and with fewer emissions.

The last point is key, as such advancements will permit greater use of coal as part of our overall least-cost energy strategy providing as well some protection for the high-sulphur coal industry of our region. Since states in the Northeast-Midwest region accounted for nearly half of the total sulphur dioxide emissions in 1980, it is important to the region that clean coal technologies be brought to commercialization as rapidly as possible.

While the Clean Air Act has achieved valuable improvements in the quality of the nation's air, many believ that coal use permitted under the act continues to pose serious environmental threats. Present Clean Air Act regulations have had a significant effect on the coal market; future large-scale reduction programs would have an even greater impact. Such a reduction plan would require retrofitting of utility plants, the expense of which leads to concerns about adverse effects om employment and electricity prices.

New Source Performance Standards provided for by the Clean Air Act are much more stringent than those for existing facilities. However, many utilities have chosen not to retire old plants, partially because of the cost of these standards. Availability of clean coal technologies could help lower the costs of meeting the standards and thereby encourage the expansion of "cleaner" facilities to meet energy needs.

Another problem in our region involves "tall stack" industries. The courts have ruled that the use of taller stacks to disperse emissions over a wider range no longer meets the requirements of the Clean Air Act. Obviously, the successful demonstration of clean coal technologies would provide utilities and industries with a range of options for meeting "tall stack" and "new sources" standards that are much more effective. Without the options that can be provided by those new technologies, future electricity growth could be hampered.

Industrial applications of clean coal technologies also are important. Industries with large, continuously operated boilers will find it attractive to burn more coal in the future. Certain basic industries, such as steel manufacturing, are facing numerous challenges in modernization and trade competition. Economical ways to meet energy needs in compliance with Clean Air Act requirements would boost the productivity of these industries greatly. Fluidized bed combustion is an example of a technology with industrial applications where the federal role in research and development has resulted in a technology that is both cleaner and cheaper. The Clean Coal Technology Reserve can play a crucial role in developing cost-effective ways of burning coal cleanly in implementing present or future Clean Air provisions.

In conclusion, it should be noted that while the administration did not request appropriations for fiscal 1986 for the Clean Coal Technology Reserve, a recent report prepared by the coal panel of DOE's Energy Research Advisory Board recommends that DOE give greater support to clean coal demonstration projects. The reserve provides the opportunity to assure industries and utilities that investments in clean coal technologies will result in cost-effective emission reduction. The cost sharing required by the reserve spreads the cost of development and uses the private sector to help identify those technologies with the best chance for success. Funding for the development of clean coal technologies can play an important role in revitalizing our regional goals of least-cost energy development, economic growth and natural resource protection.

Mr. **Walgren**. I have to express some real disappointment in the report that was submitted in response to the 1984 continuing resolution. I think I feel that you understand, also, and feel the same shortcomings of that report inasmuch as you state in your testimony that you are going to take some further steps now in pursuit of that subject and that evaluation. I keep going back in my mind to the idea that if we had had a proctor or somebody for whom we were writing a thesis of some kind we could have been redirected or told that simply the summary that was developed was not responsive to the mandate to assess these various technologies because there is very little assessing done in that process, and in that sense we failed the task; and if the time on our Ph.D. was running out, we would fear that we might not get the degree after all.

I wanted to ask, you indicate that your first effort will now be to establish criteria against which these technologies can be evaluated or assessed as I gather it. Given the fact that we have, certainly, limited budgets, the danger in this area is that the Congress or the administration would put all its eggs in very few baskets or put them in the wrong baskets, and somebody, either the Congress or the administration, has to be able to compare these suggestions. And there is no way to compare them unless we do have some criteria.

I wanted to ask very directly whether you are now embarked on setting some criteria so that one could objectively measure these proposals, and, hopefully, one of those criteria would be their near-term effectiveness in reducing of the present emission levels that we are all concerned about, and another criteria would be the breadth of their application or the degree of the problem that those technologies would reach literally. I mean we want to be pursuing something that is broadly helpful in the long run. Would that be your estimate of what the next step is now that we didn't do that in the first instance?

Mr. **Vaughan**. When you ask that question, Congressman, do you mean a prioritizing of these 176 proposals? Is that in the context of what you mean, the question?

Mr. **Walgren**. Well, it is my understanding that the request that was made for this study was focused on the 176 proposals. I would gather out of that range of proposals there would be a way to focus on groups of them. I am just looking for some way that somebody other than the Tooth Fairy could make some judgments in this area, and we don't seem to have it yet. And we are asking you to set out some method of judgment so that we can both know that you have gone through a proper process and so that someone else can look at it and compare their judgment with yours.

Mr. **Vaughan**. I think, Congressman, what you are hitting at is how or what we did in evaluating. As I think you are aware, sir, this process was specifically designed to obtain informational proposals. It was not a competitive procurement process, and that is because the Congress did not appropriate funds. And it is not fitting or proper for any agency of the Federal Government to go out to the private sector and invite a series of proposals when it does not have in hand funding to spend on those proposals and its policy does not call for activity in that general area.

Mr. **Walgren**. Pardon me, Mr. Secretary, if I might. This was the Congress asking that something be done. It was not the Executive deciding what it wanted to do or what it would like to do. The Congress is in the position, as I understand it, of needing information, and that law, which was signed by the President, became the policy of the administration. You were to assess the potential usefulness of each emerging clean technology, or clean coal technology, and you were to identify the extent to which the Federal incentives would accelerate commercial availability.

Now, we can all say until we are blue in the face that we don't believe we should accelerate the commercial availability, but that is not what the administration was asked by the Congress, and that is not what the President asked you to do when he signed that law. So, my observation is that there was precious little assessing done in that report, and there was literally no addressing of the question that you were asked by law to do, which was to identify the extent to which Federal incentives will accelerate the commercial availability.

Now, we can have that fight all the way down the road about whether we should or shouldn't accelerate the availability. But, ultimately, that is for the Congress to decide if the President picks up an initiative that comes out of the Congress, and it is not for an administrative level of our system to refuse to cooperate with. And I would almost characterize it in that degree. I don't want to be antagonistic because it is not my nature and it is not my will, and I don't think it is the most constructive thing, either. But I look at that report and I say: "Gosh, here we were asking to be put in the position where we could make this judgment if we felt it in the national interest, and we relied on the Department of Energy to provide information that would put the Congress in a very important position, and apparently somebody's bias got in the way, and in that sense, deprives the Congress for another 6 months or another 9 months from the ability to serve the national interest in a way which the President and the Congress might find very much in the national interest."

Mr. **Vaughan**. May I respond, Congressman. I believe that the report does, in fact, contain rather comprehensive technology assessments. I would specifically direct your attention to appendix C, which is a rather lengthy technology assessment section. And because we have picked up some dissatisfaction with that effort, which is not inconsiderable, the Secretary has directed that we go even further in this particular area. However, I would point out to you that technology assessments and characterizations still will not give one an automatic process by which to make funding for projects in my judgment. The only process I know of that effectively works is a full competitive procurement process, which we did not have.

Mr. **Walgren**. I guess what I am looking for is the criteria by which we might, and the administration might, evaluate these processes. I don't know that I am asking for a competitive submission, but I think it very important that we be able to make some judgment about the near-term application and about the breadth of application. And I would hope that in your effort now, as you say your first effort will be to establish criteria against which technologies could be evaluated, I hope that you would look at those two points and see what can be developed in terms of criteria that would be responsive to that, so that if we feel and if the President signs—and changes his mind. I mean things are not set in clay. The President might feel that we really ought to do something in this area at some later point—that we would be in a position to do so.

Let me also ask one other thing sort of on a philosophical level. I understand your reservations about not wanting to influence and give competitive advantage to X, Y, and Z technologies. On the other hand, I do also understand that some of these proposals for funding, particularly one, this Penn Electric system up in western Pennsylvania, where they were going to propose to use some Federal funds to run some various tests on a limestone injection burning system that they put in there. There they are not wanting to give an advantage to one system or another, as I understand it, but really only asking for some help in information collection.

Now, you indicate that some apparent advantage of Government participation in certain circumstances would be improved information dissemination. Would you agree with me that there would be a very useful role of the Government to participate in any program that would collect information, that we would think would be useful, that would not otherwise be collected by the private sector or make it more widely available so that other elements in the private sector could have the benefit of at least that much of a leg up on a technology or on a piece of knowledge?

That kind of Federal funding it would seem would not run afoul of your feelings that we shouldn't give a competitive advantage to anything. We would simply be giving knowledge, per se. Would you agree with that thrust?

Mr. VAUGHAN. Certainly I would agree on a very broad basis, Congressman. If, indeed, a proposal is for broad information. That is what we mean by the criteria "generic" that we use in our R&D criteria. That it has broad application. What we seek to avoid is using taxpayers' funds for one particular commercial entity's specific project or specific mine and, in effect, provide a competitive advantage. But in this, the broad proposition, yes, sir, I wholeheartedly endorse it.

Mr. WALGREN. OK. Let me ask one other question, Mr. Chairman, and I know that I have used more than my time. That would be that clearly in this area we have got to be hand in glove with the EPA. After all, they are making a lot of the judgments that are driving us, literally. That raises the most difficult governmental problem of coordination, and coordination is not often appreciated because it means people spending time without an awful lot to show for it, meetings and the like. And none of us appreciate just sending somebody to a meeting, but it is absolutely essential.

What is the intensity of the degree to which your office is working with EPA so that we know that there is not only full communication, but even a common purpose and a common intent and there would be the opportunity for each to develop in response to the other? Can you describe the intensity of that contact with EPA?

Mr. VAUGHAN. I believe there is a fair amount of contact between the two agencies. As you point out, certainly a number of meetings and communications between the Departments. Very specifically, we jointly serve on the NAPAP [National Acid Precipitation Advisory Panel], I believe is the correct terminology. But there are different roles for the two agencies. EPA is essentially an enforcement agency, and we are an agency in the Department of Energy that seeks to promote energy utilization in an environmentally acceptable manner. All of our efforts are aimed at making it possible to use various, and in the fossil fuel program's specific case, fossil fuels in an environmentally acceptable manner; that is, in compliance with EPA and State standards.

So, I believe there is the adequate cooperation. We routinely review EPA regulations and proposed regs from an energy viewpoint, and make our views known publicly and to EPA.

Mr. WALGREN. Well, I would just like to encourage you in that contact because I think each of you probably has some benefit that could be gained from the other, and that we will, without creating conflicts of interest, be better off in the long run with as close coordination between your two entities as we can.

Thank you, Mr. Chairman.

Mr. FUQUA. Thank you, Mr. Walgren.

Mr. VAUGHAN. Mr. Chairman, may I say something?

Mr. FUQUA. Sure.

Mr. VAUGHAN. I do believe it's appropriate for me to point out that the report does have, in view of Congressman Walgren's questions, a section that specifically addresses our views of the utility of Federal incentives. That is in the report, and I feel obliged to point that out.

Mr. FUQUA. Let me say before I recognize the next member that the Chair has been very lenient in the 5-minute rule, and we do have five more witnesses that have something important to say today. Not that we are not interested in what the Secretary has to say, but I hope we can try to bear that in mind.

Mrs. Schneider.

Ms. SCHNEIDER. Mr. Vaughan, I would just very briefly like to ask you about your assessment of the ERAB report. I recognize the value of the Advisory Board. It seems that year after year before this committee we have had some outstanding testimony presented and some interesting analyses and studies done by the ERAB. It is my understanding after reviewing some of the testimony that Mr. Reichl is going to make after you that there seems to be a conflict in the conclusions that you reach and that he reaches in terms of the need for Federal incentives in order to make some of these technologies more commercially viable.

I wonder if you could just summarize your justification for your points of view and how they differ from the ERAB report.

Mr. VAUGHAN. I think I can do that rather quickly, Congresswoman. The administration believes that we should concentrate our efforts on basic generic, long-term, high-risk R&D and that we should not be involved in the commercial demonstration phase with taxpayers'dollars. That is the essential difference.

The ERAB report, which the Secretary asked for in good faith, and that panel certainly has on it some very prestigious individuals and we tend to read that report rather seriously and to take its advice into consideration. It is abundantly clear that ERAB calls into question and specifically suggests that we reconsider this policy position about demonstration and commercialization. I think as briefly as possible that is the essential difference the two approaches.

We fully intend to consider what ERAB is telling us. On the other hand, there are many factors to be balanced and ERAB is only one of them. It is an advisory panel and its recommendations are not binding upon the Secretary or the administration.

Ms. SCHNEIDER. I realize that. Who else acts as a think tank for you, however?

Mr. VAUGHAN. Well, you act in part as your own, and then in any technological area, if your people are doing their jobs, and I think those in fossil are, they are continually aware of the theories, thoughts, positions, and ideas throughout the community that is interested. So I think that the Department in that sense is fully aware; and I, for example, have looked at the testimony that is coming to this committee from other witnesses, and I do not find those positions surprising at all. As a matter of fact, they are quite understandable and predictable.

Ms. SCHNEIDER. But they all seem to conflict with your directives.

Mr. VAUGHAN. Yes; they have one luxury I think that the administration does not have. They don't have the problem of trying to reduce Federal expenditures in some very trying times and still move forward as best you can with limited funding. We believe that the most effective use of our funding is to achieve a broad an array technologically, and that is why we are concentrated back at the technological end. We believe that we should stay out of the commercial risk-taking side; that is not something the Government is currently capable of doing well and certainly its track record in the past when it was involved in these areas was extraordinarily poor.

Ms. SCHNEIDER. Well, then it seems to me that you are caught right in the middle of the decisionmaking process because the administration and OMB has as their first priority reducing the deficit, does not have the expertise in the area of energy by any stretch of the imagination, and yet they are making policy directives and suggestions to you. Then, on the other hand, you are suggesting that ERAB and some of your own technical experts within the Department of Energy are making recommendations based on technological assessment and energy needs.

So, it seems to me that, if I were in your position, I would have to take the technological requirements and the fiscal restraints and make decisions that would serve the long-range energy needs of this country. And in looking at the direction that you are succeeding, I think that one of our greatest problems right now is that there is a lot of taxpayers' dollars that have gone to waste to develop or to do the R&D on energy technologies and those technologies are essentially sitting on a shelf.

I think one of the greatest problems this country has both domestically and internationally is that we do not have a good technology transfer mechanism, particularly in the area of energy where we are being beaten by the Japanese, the Germans, and everybody else in getting this technology from the Department of Energy out into the grassroots. It doesn't seem to me that that is part of your thrust. From my point of view, that ought to be one of the highest priorities.

Mr. **Vaughan**. Congresswoman, first I would like to say for the record that while certainly the OMB and the President give us guidelines for budget planning, OMB did not dictate and has not dictated the content of the fossil energy budget. The Secretary, and I, and the people that work for me made those budget decisions, and we set the priorities, we set the content. We did attempt to do within the constraints of funding availability, as does everybody else in the Federal Establishment, to try to live within the means that were laid out for us. So, I think we have done that balance.

Obviously, there are people who will disagree with us. Again, to talk about the dividing line or the area where the disagreement occurs, there are many who believe that the Government should have an active role in, I believe the terms are "assuring certain end uses." This administration disagrees with that. We think we should be involved in making it technologically possible for citizens, commercial entities to have the fullest range of free choices economically, but that the Government should not have predetermined through the funding mechanism what specific end uses are.

As I indicated earlier, one of the premises of the ERAB report is to cause coal utilization in utilities faster. And undoubtedly, if you fund demonstration, coal utilization in utilities will be accelerated. But the question that we would raise is, is that the wisest use of available funds? And there we would differ. I think that is a place where we would respectfully differ.

I have no quarrel with the members of this panel who drafted this report because I think they, given the premises, the report hangs together. In like fashion, I think given the premises that I have stated our position is not surprising.

Ms. **Schneider**. Well, thank you. I am afraid that my time has expired, but I will be anxious to hear from the witnesses that follow whether or not they have any concern for fiscal restraint in their policy recommendations. Because I think it is important that that point reach you and that future decisionmaking be done in that context.

Thank you, Mr. Chairman.

Mr. **Vaughan**. It may be useful to point out to the committee that this effort, if you simply total up the amount of funding involved, calls for some more than $8 billion of additional funding. So, certainly in toto it would appear that fiscal restraint was not an overriding factor by the submitters.

Mr. **Fuqua**. Thank you, Mrs. Schneider.

Mr. Stallings.

Mr. **Stallings**. No questions.

Mr. **Fuqua**. Mr. Cobey.

Mr. **Cobey**. No questions, Mr. Chairman.

Mr. **Fuqua**. Mr. Traficant.

Mr. **Traficant**. Yes, Mr. Chairman, thank you.

I just want to echo the comments, and I think the perception, of the Congresswoman from Rhode Island. It is about right on, and philosophically I have to embrace that.

Here is my particular question. Although I missed the earlier part of your testimony, I keep hearing the short time I am here about the use of taxpayers' dollars for commercial risk taking. My question is when do we start investing rather than spending? Even though I am new, I think we are still rather dependent on foreign countries for energy needs in this nation. What is the long-term prediction, if we are not going to spur investment by Government intervention with the tremendous resource we have in coal that right now is being underused, undermaximized, while we are still spending literally millions of dollars in Third World nations that have us rather dependent for energy needs?

So, in line with some of her questioning and comments relative to ERAB and the think tank that exists, how do you foresee our removing ourselves from this dependency? Because we are still spending taxpayers' dollars, sir. We are spending them in other areas. Perhaps maybe you can comment along those general lines as far as your overall long-range goals of investment versus spending, which it seems we are doing for foreign oil and other energy sources.

Mr. VAUGHAN. First, Congressman, other than the money that is used to purchase oil for storage in the Strategic Petroleum Reserve, and I feel I must point out it is spending surely for energy, but it is spending by our citizens, not by the Government itself. Here we are talking about what we are going to do with dollars that we have collected in the form of taxes and then how we are going to put them back in the system. In the specific case of fossil energy, we are trying to develop in a fiscally constrained atmosphere the widest array possible of technological options for our entrepreneurial risk-taking private sector to then exploit as it sees fit; and I think that is what we are trying to do.

Now, generally I think this administration has an unparalleled record in the area of reducing dependence on foreign sources of energy. Certainly, more progress has been made in this administration on that score than any of its predecessors.

Mr. TRAFICANT. Well, then just briefly, how do you account for the wide range between your think tank contained within DOE and ERAB and their report?

Mr. VAUGHAN. ERAB's premises, Congressman, were to accelerate the use of coal in utilities. That is basically what their report is about. It is undoubtedly true that if you pour millions of dollars from any source into that process, yes, you will accelerate the rate at which coal is used by utilities. I do not argue with that at all. I think there is no doubt that would occur.

The question is, is that the wisest use of limited Federal research and development dollars? And there is the difference.

Mr. TRAFICANT. I thank you, Mr. Secretary. No further questions, Mr. Chairman.

Mr. FUQUA. Thank you very much, Bill. We appreciate your being here this morning. I think you can tell from the questions and so forth there is a considerable amount of interest in this subject, and we appreciate your being here with us today.

Mr. VAUGHAN. Thank you, Mr. Chairman.

Mr. FUQUA. Our next witness is Eric Reichl, who is most recently a nominee to the Synthetic Fuels Corporation Board, and I think that his background would be a very excellent addition to that Board.

We want to welcome you to our subcommittee. Your comments on the DOE emerging clean coal technologies will be appreciated, and we also hope that you can discuss your clean coal use report which was accepted by DOE's Energy Research Advisory Board last week and has already been mentioned in questioning today. We are very happy to have you.

STATEMENT OF ERIC REICHL, CHAIRMAN, CLEAN COAL USE PANEL, GREENWICH, CT

Mr. Reichl. Thank you, Mr. Chairman. I appreciate the opportunity to appear before the committee and to discuss the ERAB report, which has been noted heretofore. I think it might be worth pointing out, as Mr. Vaughan has already done, that ERAB is really part of the Department of Energy. It is not independent of it and feels to be very much a part of it. It is an independent think tank supposedly and should bring to the Department the views from the outside. That is what they have done.

As you know, Secretary Hodel, at the time, in April of last year, had asked for this review of the clean coal use technology, and we have prepared this report which has just been completed. I happen to have been the chairman of the panel that is reponsible for the report; however, I want to take this opportunity to note that obviously the cooperation that we received from the panel members, both those that came ERAB itself and those that came from industry outside and academia, was most helpful and the report couldn't have been put together without it. I think we have had a set of experts that was second to none in this field.

I would like to make a few comments about the report, and then I guess answer your questions.

First of all, as you have noted, the subject is quite diffuse. It isn't a simple issue of how one uses coal cleanly, and for that reason, we divided the report up technically in the specific areas that you would normally think of in terms of dealing with coal before you burn it, while you burn it. We then subdivided that issue into pulverized coal burning and fluidized bed burners and flue gas cleanup. We added a section on waste management, which is an important issue. And in order to get some feel about the importance of the subject, we had asked for a summary of the coal use as it was to be forecast for the next 150 years to see which direction this technology should be driven.

I would like to also draw attention to another subject that I think is quite important in considering the scope of this report. Since I do wear two hats, as it were, one at the Synthetic Fuels Corporation and one at ERAB, I want to draw your attention to the overlap that does exist between technologies that relate to clean coal combustion power generation and those that relate to synthetic fuels. And quite narrowly we have assumed that the use of high-pressure gasification with oxygen would be considered a synthetic fuel technology, and it is not treated in this report, although we all know it is an excellent means to use coal cleanly. The cool water project, specifically, is a good example here.

I believe we have good reasons not to include it here because this area is going to be covered very thoroughly with a lot of money if we are permitted to do so through the Synthetic Fuels Corporation. I am making a point of it because we have included in the scope here the use of air-blown gasifiers, which are narrowly used for clean coal combustion, and while this is a technical fine point I think it is an important one to distinguish between moneys used in clean coal technology and those used for synfuels.

I should say that the report was submitted to the full Energy Advisory Board on May 1 and was accepted with minor changes, and it will be issued shortly, as soon as these changes can be incorporated. And I would like your permission to insert this full report as part of this testimony because it is in the report where you can read all the details that the various panel members have suggested.

Mr. FUQUA. Without objection, we will make that part of the record.

Mr. REICHL. Thank you.

[The report follows:]

Energy Research Advisory Board
to the
United States Department of Energy
1000 Independence Avenue, S.W.
Washington D.C. 20585
(202) 252-8933

Mr. Ralph S. Gens
Chairman
Energy Research Advisory Board
Washington, DC 20585

Dear Ralph:

I am pleased to submit to you the Panel's report on Clean Coal Use Technologies. Changes that the Board discussed at the May 1 meeting have been incorporated, and I consider this to be the Panel's final product.

The burning of coal for electric power generation and other purposes is expected to increase into the 21st century. Because of the various potential environmental and health consequences of coal combustion, the Panel believes that the Department has a role to play not only in clean coal R&D but also in selective demonstration of technologies. Principal R&D needs are spelled out in the report. However, the Department should undertake a demonstration only when co-funding of more than 50% is provided by industry to ensure early application of the technology.

The Panel very much appreciates the cooperation and assistance of DOE Headquarters and the Energy Technology Centers during the course of the study.

Mr. Eric Reichl
Chairman
Clean Coal Use
Technology Panel

Attachment

ENERGY RESEARCH ADVISORY BOARD
CLEAN COAL USE TECHNOLOGY PANEL
JUNE 1984

*Eric Reichl, Chairman
President (Retired)
Conoco Coal Development Company

*Betsy Ancker-Johnson
Vice President
General Motors

*John Landis
Senior Vice President
Stone & Webster Engineering Corp.

*William McCormick, Jr.
President
American Natural Resources Co.

Joseph Mullan
Senior Vice President
National Coal Association

*Lawrence Papay
Senior Vice President
Southern California Edison Co.

*Ruth Patrick
Limnology Department
Academy of Natural Sciences

William Poundstone
Consultant

Frank Princiotta
Director
Industrial & Environ. Research Lab
Environmental Protection Agency

Edward Rubin
Director
Center for Energy & Environ. Studies
Carnegie-Mellon University

*Victoria Tschinkel
Secretary
Dept. of Environmental Regulation
State of Florida

Kurt Yeager
Vice President
Coal Combustion Systems Division
EPRI

*Ralph Gens (Ex Officio)
Chairman, ERAB
Consulting Engineer

STAFF
Charles Cathey
Executive Secretary
ER-6, Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585
(202) 252-8933

*ERAB Member

May 1985

ENERGY RESEARCH ADVISORY BOARD

Ralph S. Gens, Chairman
Consulting Engineer

Betsy Ancker-Johnson
Vice President
Environmental Activities Staff
General Motors

Frank Baranowski
Consultant

Ivan L. Bennett, Vice Chairman
Professor of Medicine
New York University Medical Center

Melvin Calvin
Professor of Chemistry
Department of Chemistry
University of California

William D. Carey
Executive Officer
American Association for the
Advancement of Science

Floyd L. Culler, Jr.
President
Electric Power Research Institute

Gerald L. Decker
President & Chief Executive Officer
Decker Energy International, Inc.

Mildred Dresselhaus
Professor
Massachusetts Institute of Tech.

Arthur Hansen
Chancellor
Texas A&M University System

Robert L. Hirsch
Vice President, Exploration &
Production Research
ARCO Gas and Oil Company

Charles J. Hitch
President Emeritus
University of California

John R. Huizenga
Chairman
Department of Chemistry
University of Rochester

John Landis
Senior Vice President
Stone & Webster Engineering Corpotion

Henry R. Linden
President
Gas Research Institute

William T. McCormick, Jr.
President
American Natural Resources Company

Lawrence T. Papay
Senior Vice President
Southern California Edison Company

Ruth Patrick
Limnology Department
Academy of Natural Sciences

David Pimentel
College of Agriculture
Cornell University

Robert H. Pry
Consultant
Center for Innovative Technology

Eric Reichl
President (Retired)
Conoco Coal Development Company

Louis H. Roddis, Jr.
Consulting Engineer

Francis G. Stehli
Dean, College of Geosciences
University of Oklahoma

Victoria J. Tschinkel
Secretary
Department of Environmental
Regulation
State of Florida

STAFF

Joel A. Snow
Acting Executive Director
Energy Research Advisory Board
Department of Energy

EXECUTIVE SUMMARY

This report by the Energy Research Advisory Board (ERAB) Panel on Clean Coal Use Technologies has been prepared in response to a request, dated April 24, 1984 from the Secretary of Energy Donald Hodel.

The Panel was convened and met on four occasions. Individual members met with DOE staff and visited the DOE Energy Centers to receive briefings on the DOE program. Drafts of individual sections were reviewed by all Panel members and the final draft was approved by the full ERAB at the May 1, 1985 quarterly meeting.

To assure proper coverage of the subject, it was divided into sections dealing with the following areas: pre-combustion; combustion in conventional systems (pulverized coal); combustion fluidized beds; post combustion (flue gas cleanup) and waste management. A section on the expected future use of coal in utility and industrial furnaces was added to determine the markets where clean coal use technologies are to be applied.

In defining the scope of the report, it was decided at the outset not to cover the subject of health or environmental impact resulting from the use of coal--although the development of control technology (i.e., the subject of this report) must be conducted in close coordination with R&D on these impacts.

A second important definition of the scope relates to the areas where clean coal use in combustion overlaps with synthetic fuels technology. Specifically, it was decided that gasification of coal with oxygen under pressure would be considered a synthetic fuels technology, where it actually occupies a very central position. This does not deny the obvious importance of this step in clean power generation, but it is not included in the report and it is not recommended to DOE. Alternate configurations of this technology are expected to receive very extensive support from the Synthetic Fuels Corporation.

Conversely, the conversion of coal to low BTU gas in airblown gasifiers is included among the clean coal use technologies, where it is treated as two-stage combustion although it can also be viewed as a pre-combustion clean-up system. The seven individual sections of the report cover their respective areas in detail and the reader is urged to consult them for information on the status and recommended programs to bring various new technologies to commercial readiness. In most instances this requires testing at substantial scale, because the key user, i.e. the electric utility industry, is uniquely sensitive to the need for fully tested and proven reliability and effectiveness of a new technology before it can be adopted for use in power generation. The scale suggested for each technology is given in the report, as is an approximate estimate of total program cost for a 5 year period.

At the present time, DOE policy does not include direct support of commercial demonstration, leaving this final and most critical step to the private sector alone. A key recommendation of the report to DOE is a reconsideration of this policy as it applies to the clean use of coal.

The conclusions from each subsection are summarized and discussed in the report. Major items are the following:

- o The use of coal during the next quarter century is expected to grow at a slow but steady pace (most of it consumed in utility boilers), with particular emphasis on the continued use of coal in existing installations. Therefore, demonstration of clean use technologies which can be retrofitted warrants special consideration.

- o The Panel notes the wide range of available alternates and concludes that selection of preferred systems will be extremely site specific. There is no way to select any one preferred approach by ranking the many different concepts. The factors which can affect the choice at any given site will include plant size, plant life remaining, type and price of available coals, location or space for added equipment, ponds, etc., applicable regulations on emission, and others.

- o Therefore, a proper DOE program should offer a reasonable choice of alternates, leaving selection of technology to the private sector. This selection process by the marketplace will best determine which systems deserve DOE support. By insisting on a major private sector contribution of at least 50% of the project cost, the best assurance of early commercial application can be obtained. DOE should require this level of co-funding, particularly as the more costly demonstration phase is entered.

- o The report lists some 13 to 15 categories of technologies for clean coal use and there are numerous competitive approaches available in most of these categories.

If each of these categories is pursued all the way through proper demonstrations by at least one major project to commercial readiness the total program cost, over a 5 year period, is estimated at $1.9 billion. Obviously, the cost will be less since some technologies will fall by the wayside.

While most of the funds would be expected to come from the private sector, a contribution by DOE of 30% on average is believed adequate and warranted to assure an expeditious execution of the program.

The Panel believes this is necessary to assure the continued viability of the coal option. The program relates to health and environmental issues, and is thus a most appropriate area for direct DOE support and involvement.

REPORT OF ERAB PANEL ON CLEAN COAL USE TECHNOLOGIES

TABLE OF CONTENTS

VOLUME I — Page

EXECUTIVE SUMMARY iv

I. BACKGROUND 1

II. THE FUTURE OF COAL IN THE U.S 2

III. COMMENT ON ECONOMICS OF CLEAN-UP TECHNOLOGIES 2

IV. GENERAL COMMENTS FOR DOE CLEAN COAL USE PROGRAM 3

V. TABULATION OF PROGRAMS 6

VI. REVIEW OF CLEAN COAL USE TECHNOLOGIES 11

VII. SUMMARY RECOMMENDATIONS 12

VOLUME II

A. THE CLEANING OF COAL: By W. Poundstone & E. Rubin 1

B. COMBUSTION - I. PULVERIZED COAL COMBUSTION: By J. Landis & F. Princiotta 16

C. COMBUSTION - II. FLUIDIZED BED COMBUSTION: By K. Yeager 54

D. AIRBLOWN GASIFIERS: By W. McCormick 86

E. POST COMBUSTION EMISSION CONTROL: By L. Papay 89

F. WASTE MANAGEMENT: By E. Rubin 106

G. PROJECTED COAL UTILIZATION IN THE U.S.: By J. Mullen 115

REPORT OF ERAB PANEL ON CLEAN COAL USE TECHNOLOGIES

I. BACKGROUND

By letter dated April 24, 1984 Secretary Don Hodel requested ERAB Chairman Ralph Gens to assess the principal technologies for the clean use of coal. For each area, the letter asked for a review of:

- the current Department of Energy, private sector, and foreign research and development effort;
- the relative cost-effectiveness of alternative technologies for the clean utilization of coal resources;
- the adequacy and timing of this work in reference to the national need.

A copy of the letter is Appendix A.

ERAB accepted this assignment and a Clean Coal Use Panel was established. The membership list is on page i. (See also minutes of May 3-4, 1984 meeting of ERAB).

The subject of the study is widely dispersed and to cope with this problem it was subdivided into three major areas, covering respectively pre-combustion, combustion proper and post-combustion technologies. Combustion proper is subdivided into conventional (pulverized coal), fluid bed, and pre-gasification combustion systems. Subpanels were established to cover each of these areas in detail. In addition, an outline of the predicted use of coal for the period 1985 to 1995 and beyond was provided to relate the several technologies to the potential market.

This report concerns itself with the development of emission control technology. It does not cover the environmental impact and health research programs at DOE or elsewhere. The two areas are, of course, related to each other. Thus, R&D efforts in both should be properly coordinated to assure that the various control technologies take cognizance of the environmental and health effects which may result from their application.

Another limitation of the scope of the present study relates to the obvious overlap between certain clean coal use as against synthetic fuel technologies. A key example is the pressurized oxygen blown gasification of coal. It was decided to limit this report to those types of gasifiers which cannot serve the conversion of coal to synfuels. Thus airblown atmospheric units are included here, while oxygen blown pressurized units are omitted even though it is recognized that the latter are one of the most significant new systems for clean coal use in power generation (and synthetic fuels) which is receiving major attention at this time.

The Panel met on July 31, November 14, 1984 and January 16, 1985 to review progress and to discuss the initial drafts covering the assigned subjects.

There were numerous contacts and visits with representatives of DOE and of the private sector in addition to these panel meetings. As a result of the large volume of material to be reviewed and the broad magnitude of the task, it was not possible to comply with Secretary Hodel's initial request for completion of the report by November 1984.

Nevertheless, it is hoped that the resulting 6 month delay will not detract from the usefulness of the study, which covers a subject of major interest to the U.S. energy industry and which has recently received increased attention in Congress.

The Panel wishes to thank the management and staff of DOE who were ready at all times to help and who supplied extensive written and oral information on DOE programs, budget and goals. Finally it is a pleasure to report that we have found the DOE Research Center facilities well maintained and the work competently executed and reported. The intent of this report is not to be critical, but to help point the work in the direction which is believed to be most appropriate and in tune with the national goal of using coal cleanly.

II. THE FUTURE OF COAL IN THE UNITED STATES

As a result of several major independent trends, the use of coal in the U.S. is expected to continue to increase at a reasonably steady pace for most of the next 25 years. The two major influences causing this trend are the continued high (compared to coal) price of oil and the reduction in the expected future of nuclear power. Add to this the expected continued move toward electricity and the importance of the future use of coal in power generation emerges as one of the key long-range trends in the U.S. energy balance.

It was therefore particularly timely to determine whether U.S. efforts in general and those of DOE in particular are properly directed toward assurance that the increasing use of coal will be matched by an increased effort to minimize the insult to the environment. Among the several uses of coal, combustion is by far the largest contributor for the foreseeable future. Thus, the present report focuses on this subject.

To establish a quantitative basis for the potential future application of the results of Clean-Coal-Use R&D, Section G of Volume II of the study presents an outline of the expected coal market in the near and intermediate term. This section was prepared by Mr. Joseph Mullan, Senior Vice President of the National Coal Association.

III. COMMENT ON ECONOMICS OF CLEAN-UP TECHNOLOGIES

In his original request, Secretary Hodel had specifically asked for information on the relative cost-effectiveness of alternate technologies. After careful review of the available information the Panel concludes that no clear-cut answer to this question is possible.

This is not to say that estimates of the cost of the many types of processes are not available or are meaningless. In fact, the several chapters in Volume II of this report present a considerable range of such costs. However, the number of specific coal use situations is so large and diverse and the specific problems are so site-specific that no generally applicable answer can be presented. The issue is particularly difficult when applied to retrofit problems which represent the overwhelming majority of applications.

For any installation where coal is burned (new and existing) and where technology is to be considered for reducing the emissions of pollutants into the air, water and soil, every technology discussed in this study deserves consideration, at least in principle. This includes precombustion cleaning of the coal, modification of the combustion apparatus proper (including its replacement) and clean-up of the flue gas. Given the many specific facets of any particular case it will then probably be possible to eliminate a good many of the technologies out-of-hand, leaving the final choice subject to a very detailed analysis of the relative cost-effectiveness of a few competitive systems.

As a result, the relative cost-effectiveness promised by alternate technologies cannot be a valid guide to selection of R&D programs, except in those cases where projected costs are evidently well outside those of alternate systems. Examples of this are noted in the chapters covering the several areas.

This entire subject of clean use of coal and the related R&D is a good example of the potential danger of "central decision making". The subject is much too complex to lend itself to a rigorous comparative economic analysis and is much better left to the marketplace for selection. In effect, the best criterion for inclusion of an R&D project in DOE's program would be significant co-funding by a group of potential USERS of the technology. This co-funding issue arises increasingly as a concept moves from initial conception and exploration on the bench, to proof of concept and finally to demonstration.

DOE policy has recently excluded work beyond the proof of concept stage; this report indicates where this limitation may prevent timely commercialization of new technologies, and a revision of this policy is recommended. At the same time, it is re-emphasized that as R&D costs rise sharply when demonstration is undertaken, this must be accompanied by substantial (i.e. more than 50%) co-funding to assure that the work will find early application.

Willingness by a group of potential users to co-fund a project is the best assurance that a project promises to be cost-effective. No user is likely to risk substantial R&D money unless he can see an early application given technical success of the venture.

As an aside to clean-up economics, one should note that main attention has generally been given to potential pollution of the air. This should, however, be balanced by the recognition of possible trade-offs which may be required between pollution of air, water and soil. Economic analysis must include the impact resulting from any technology on all three of these areas.

IV. GENERAL COMMENTS FOR DOE CLEAN COAL USE PROGRAM

The preceding paragraphs have already suggested one particular useful criterion, i.e., co-funding. However, there are some other considerations worth noting.

- The need for Basic Research.

  Coal has been the subject of R&D for 200 years and almost every conceivable scientific discipline has been brought to bear on coal as it was developed. An excellent central reference to these efforts is available in the several editions of H. Lowry's "Chemistry of Coal Utilization" (John Wiley & Sons, publisher) with the latest edition covering work up to about 1973. No work should be undertaken before this source has been carefully checked to avoid "re-inventing the wheel", which is not infrequent in this area.

  The last 10 years have seen the arrival of some entirely new and very powerful concepts in solid state physics, optics, etc. which are only now beginning to be applied to coal and coal based operations. There is a great need for NEW fundamental facts and knowledge about coal, because the old available knowledge has been exhaustively applied and exploited; no major innovation can be expected simply by "revisiting" it.

  An important criterion for DOE should therefore be the accumulation of new basic data related to coal. A specific area which is in need of better insight is the occurrence, the origin, the composition and the forces bonding mineral matter to the coal substance. Such knowledge might open the door to improved coal cleaning concepts. However, there are certain other coal-related areas which would also benefit from new fundamental research, including combustion, coal composition, etc.

- Distribution of Available R&D Funds Among Alternate Areas

  Review of the DOE Fossil Energy budget shows that about 30% of the total coal program is devoted to the clean direct use of coal (i.e., coal combustion). Yet direct combustion will continue to represent over 90% of all coal use for the rest of the century and beyond. Thus an imbalance exists between the several coal uses and the related R&D budgets.

  This brings up a problem, recognized by the Panel, i.e., the wide use of Congressional Mandates for specific projects, which takes the selection out of the hands of DOE. The problem is beyond the scope of this report, but it points up the permanent need for good liaison and a continuing educational process with the several Committees which have cognizance of the R&D budget.

  As to distribution of R&D funds within the several key areas of clean-use technologies covered by this Panel, the best criterion will be the "marketplace" as discussed in the preceding section. The best litmus test will be the willingness for private sector co-funding and particularly co-funding by a potential user group of the technology rather than a seller of it.

- Advice from Industry in Selection of Program

  DOE cannot pursue all promising areas, and therefore selection or establishing of priorities is required. In this context it is recommended that the private sector be involved in the decision-making. Use of special ad hoc advisory panels from industry is a possible format. DOE personnel cannot have the needed day by day contact with the operational problems arising from the many new technologies and an industrial panel can bring this experience to the point where R&D decisions are made.

- Policies Outside DOE-which Influence R&D

  Attention needs to be given to policies, or regulations, laws, etc. which affect clean-up technologies now and even more to those policies, etc. which are likely to arise in the future. These factors must be kept in mind in choosing an R&D program.

  Examples are Best Available Coal Technology (BACT), New Source Performance Standards (NSPS), Acid Rain Legislation, and Resource Correction and Recovery Act (RCRA). DOE must be concerned at all times about the direction in which these policies or laws will take the nation, and hopefully anticipate the needs when choosing an R&D program.

- Inter-Agency Cooperation and Information Exchange

  In the course of this study it became apparent that greater cooperation between the several entities in the field would be desirable. This is particularly needed between DOE and EPA, where more coordinated co-funding could help speed up completion of certain urgent clean-up R&D programs.

  However, this is not only a matter of co-funding, but also one of bringing to bear the R&D strengths available from each organization in selected areas to complement each other.

- DOE Leadership

  DOE has a unique opportunity and an obligation to exert leadership in Coal-Use-Technology R&D, particularly because the general subject includes such a wide range of topics.

  The DOE budget, even if it were expanded, would not be sufficient to pursue all projects (especially large-scale demonstrations) deserving support.

  However, the concept of co-funding, which may involve well over 50% private sector contribution, will allow DOE to cover a broad program by leveraging the DOE funds. At the same time, DOE can assist industry by putting the needed project-packages together and thereby assuring readiness of the technologies when new laws and regulations may call for their deployment.

  In this context, note that direct co-funding is only one way in which DOE can help. DOE should also lead, when opportunities arise, in urging use of tax incentives which could result in large private sector R&D efforts and would reduce the need for direct DOE involvement.

  Finally, leadership also calls for stability of program and purpose, especially where co-funding is involved. A prime concern of private sector R&D management, when dealing with DOE, is assurance that program direction and budget, once adopted, will not be changed arbitrarily. This is most important to the larger multi-year projects where change in direction is costly and wastes resources. In this connection the DOE track record is poor. Improved stability would facilitate commercialization of viable new technology.

V. TABULATION OF PROGRAMS

The reader is urged to consult Volume II of the report for detailed reviews of the major technologies. Here, we summarize the overall findings in a compressed format to make it easier to understand the relationship of the several sections. This is done in tabular form in Table I, including very brief comments on application, status, range of effectiveness, time of commercial readiness and an appropriate estimate of the total program cost for the 5 year period of 1986 to 1990.

The entire program, assuming that every area will be developed to commercialization, would represent $1.9 billion, as shown on Table II. It is of course quite unlikely that every option will be pursued to completion. Thus, the total cost would be considerably less.

The Table does not indicate what part of this total cost would be contributed by DOE, but it is expected that the majority will come from the private sector. A reasonable DOE contribution would be up to 1/3 of the total on the average, leaving choice of contribution to individual projects up to DOE management. In chosing areas for particular attention, the following four points are noted:

- With clean-up of existing coal burners representing the main challenge in the near term, the early demonstration of RETROFITTABLE technology is most urgent.
- Using current Post-Combustion clean-up technology as a yardstick, improvements to this and hopefully lower cost technology appears as the appropriate target. This suggests limestone injection multi-stage burners (LIMB) and improved flue gas desulfurization (FGD) as the first priorities. Aggressive pursuit of this target will make full deployment possible around 1989-1990.
- Several alternates exist which can bring about the displacement of oil or gas with coal in existing stationary combustion systems. This includes new concepts for coal cleaning (combustion of coal/water mixtures), a new type of slagging burners, and use of micronized coal. By definition, displacement of oil or gas also implies the use of coal in a cleaner manner.
- For new facilities and certain retrofits, fluidized bed combustion offers a new alternative. With atmospheric fluidized beds already in the market place, the main DOE emphasis would properly be placed on the pressurized version. If the promise of this technology stands up it may reach commercial status in the early 1990s.

TABLE I
SUMMARY OF CLEAN COAL USE TECHNOLOGIES

DESCRIPTION	APPLICATION or PRIMARY USE	STATE OF DEVELOPMENT	REQUIRED SCALE OF COMMERCIAL DEMONSTRATION	MAXIMUM RANGE OF EFFECTIVENESS	TOTAL COST* OF PROGRAM 1986-1990 $ MILLION	AVAILABLE FOR USE
I. Pre-Combustion						
1) Physical cleaning of fine size coal	Retrofit (may be combined with other technologies) to lower SO_x (partial) by removing pyrite also	Commercially available. Improvements to be tested at Homer City pilot	Cleaning step tested individual trains at 10 T/hr (impact on combustion tests require large scale)	30-40% SO_x (80% pyrite recoverable)	62	Current
2) Chemical cleaning	To replace oil/gas by reducing ash to 2% or less	In progress	Chemical processing of coal would require demonstration at several 100 T/D	90% SO_x, 90% ash removal claimed	37	After 1990
3) Miscellaneous	------------------	-------------	Coal characterization (incl. comminution)	---------------	21	-------
II. Combustion - I Conventional (PC) Firing:						
1) Micronized Coal Combustion: Coal is pulverized to pass 100% thru 325 mesh (44 micron). Special mills required at site of burner.	Retrofit To replace oil/gas in utility and industrial boilers without derating boilers	Special mills of 20 Ton/Hr capacity tested. 100 MW gas fired boiler tested w 1/3 coal in furnace. Also in industrial use with mechanical roller mill.	Utility burn-test at 300 MW range required.	Not primarily a pollution control technology. (Micronizing will liberate more pyrite and ash.) Demonstration with electrostatic cleaning being planned.	100	1990
2) Coal/Water Slurry Combustion: 70% solid concentration proposed. Can be prepared wih coal ground to either: a. pulverized (PC) grind or b. micronized grind. Can be combined with new fine size coal cleaning.	Retrofit To replace oil/gas in utility and industrial boilers. CWS can offer cleaner coal, i.e., some SO_x reduction. a. PC grind CWS required derating; b. micronized grind does not.	a. 150 Ton/Day PC grind CWS pilot plants operating. Combustion tests in industrial boilers completed. b. Test quantities of micronized CWS produced.	a. Utility burn--tests of PC grind CWS required at 300 MW range (i.e. approx. 3000 T/day;) b. small scale tests of micronized CWS succesful. Require scale-up.	See I above. Not primarily a pollution control technology.	151	1989-1990

*These costs to be shared between DOE, EPA, Industry and others

TABEL I CONTINUED

DESCRIPTION	APPLICATION or PRIMARY USE	STATE OF DEVELOPMENT	REQUIRED SCALE OF COMMERCIAL DEMONSTRATION	MAXIMUM RANGE OF EFFECTIVENESS	TOTAL COST OF PROGRAM 1986-1990 $ MILLION	AVAILABLE FOR USE
3) 2-Stage Slagging Burner Cyclonic burner installed outside furnace to remove 85% ash by tapping slag. Can be combined w. sorbent injection.	Retrofit space requirement may limit application at industrial and utility boilers. May be applicable to coal fired gas turbine.	Proof-of-Concept available in 1/2 ton/hr burner. 2 Ton/hr burner to be tested in industrial boiler.	Utility application may require development of larger burner. Needed size is site-specific.	60-80% SO_x claimed possible w. sorbent. 250 ppm SO_x attained.	70	1990
4) LIMB Sorbent injection in furnace to react w. SO_x can be combined w. LO-NO_x burner	Retrofit To reduce SO_x (partial) at lower cost than FGD. Can be combined with coal-cleaning	100 MW wallfired boiler test scheduled. (Represents 1/2 of units)	100 MW tangential boiler test required (Represents 1/2 of units)	50-60% SO_x for retrofit. Can Can be higher for new installations.	41	1989-1990
5) LO-NO_x Combustion NO_x suppression (partial) obtained by reduced O_2 in primary flame, lower peak temp., shorter hi-temp. residence time.	Retrofit To obtain some reduction of NO_x. Will require new burner, or gas recycle etc. Impact site specific.	Test at pilot furnaces; limited field testing. Long term retrofit issues unresolved.	Full-Scale (300 MW) utility demonstrations required on range of boilers	25-60% NO_x reduction, depending on specific furnace.	57	Current
Combustion - II Fluid Bed Burners						
1) Atmospheric Systems: Both bubble type and circulating units available competitively.	Mainly for new installation for industry and smaller utility units. 100 MW boiler being retrofitted.	Both bubble types and circulating systems commercially used in industry. Extensive R&D still in progress toward improvement.	100+ MW utility boiler being built.	90-95% SO_x. NO_x reduced well below NSPS level (0.1-0.2 lb/MMBTU). Particulate emission comparable to conventional combustion.	314	Current

TABEL I CONTINUED

DESCRIPTION	APPLICATION or PRIMARY USE	STATE OF DEVELOPMENT	REQUIRED SCALE OF COMMERCIAL DEMONSTRATION	MAXIMUM RANGE OF EFFECTIVENESS	TOTAL COST OF PROGRAM 1986-1990 $ MILLION	AVAILABLE FOR USE
2) Pressurized Systems: The appeal lies in possible shop-fabricated 100MW modules which would help utilities in particular.	New Installations for stepwise additions to utility plants. May offer higher efficiency than present technology.	Proof-of-concept under way abroad. Alternate PUC plant built in US never put in operation (At Curtis-Wright).	100 MW module is final target for development.	Same as above	343	1990-1992
Combustion - III Lo BTU Gasification Includes fixed bed and fluid bed gasifiers using air blast. Gas clean-up required. Lo BTU level of gas (120-130 BTU CF) limits use.	Retrofit To replace oil/gas industrial (and some utility) furnaces. Requires tight integration with user.	Competitive gasifiers available. Testing with certain coals required. Gas clean-up critical; requires development, as does testing of Lo BTU gas in user equipment.	Gasifiers with 100-200 Ton/Day to be tested with coals of varying specifications. Gas clean-up section to be included in test.	95% SO_x and 100% particulate. % NO_x user-dependent. (Emissions, if any are from gas clean-up unit).	100	1984-1990
III. Post Combustion: Includes all technologies for flue gas clean-up to remove SO_x/NO_x and particulates. This technology (FGD) is in current use and represents "PAR FOR THE COURSE". Any alternate clean-up technology must be compared to it in terms of cost and effectiveness.	Retrofit In principle this can be applied to all combustion, subject to space requirements (which can be prohibitive). 90% of plants using sorbent on "throw-away" basis. Disposal is major problem.	50,000 MW are in commercial operation. This is "State of the Art." Many innovations range from R&D Proof-of Concept to full scale testing.	For acceptable credibility (in utility use) any new system requires testing at least at 100MW or larger scale for 1 year or longer.	Wet Scrubber: 90-95% SO_x Dry Spray: 60-90% SO_x Catalyt. Red'tn: SCR: 50-80% NO_x ESP: 99.7% particulates Baghouse: 99.9% particulates		Current

TABEL I CONTINUED

DESCRIPTION	APPLICATION or PRIMARY USE	STATE OF DEVELOPMENT	REQUIRED SCALE OF COMMERCIAL DEMONSTRATION	MAXIMUM RANGE OF EFFECTIVENESS	TOTAL COST OF PROGRAM 1986-1990 $ MILLION	AVAILABLE FOR USE
1) Improvements aimed at production of saleable gypsum ($CaSO_4$).	Sale of gypsum would lessen waste disposal problem.	Competitive system demonstrated abroad. Chiyoda, Dows, etc.	Same as above	Same as Above	238	1990
2) New FGD aimed at combined SO_x/NO_x removal & producing sulfur for sale.	Applicable to most situations if economics warrant.	R&D or Proof of Concept. Includes NOXSO-SULF-X, CuO-E-Beam, etc.	Same as above	Same as Above	322	Beyond 1992
Baghouse Lime Injection: Powdered lime injected upstream of fabric filter; may require flue gas temperature conditioning	Retrofit requirement for baghouse may limit application	Proof-of-Concept at 0.5 MW	100 MW utility demonstration required	40-60% SO_2	10	1990
IV. WASTE MANAGEMENT: Includes all aspects of solid waste disposal and/or utilization. Current DOE activity characterization of wastes from operating plants and potential impact of RCRA. Planned: characterization of wastes from new technologies.	Important to all coal firing systems as far as coal ash is concerned. Of major concern where sorbents are used to pick up SO_x	Ash utilization under increased attention from private sector (incl. use of flyash in cement). Processing of scrubber-sludge used occasionally.	N/A	N/A	60	Current

TABLE II

Order of Magnitude Estimate of 5 Year Program Cost
(in $ Million)

Description	Total 5-Year Cost of Program
Precombustion	$ 120
Conventional Combustion	419
Fluid Bed Combustion	657
Airblown Gasifier	100
Post-Combustion	570
Waste Management	60
TOTAL	1,926

It is re-emphasized that for optimal allocation of resources (both of DOE and of the private sector) every project must be specifically reviewed with regard to these factors:

1) Potential contribution to emission control
2) Cost/benefit ratio
3) Time frame
4) Probability of technical and economic success
5) Industrial need (as measured by available co-funding)

VI. REVIEW OF CLEAN COAL USE TECHNOLOGIES

Volume II comprises the main substance of the report. The subject was divided into five areas of technology and the lead for the review of each was taken by the Panel members indicated below:

o Precombustion

The Cleaning of Coal: W.N. Poundstone & E.S. Rubin

o Combustion

A. Conventional (PC) Coal Combustion: J. Landis & F. Princiotta

1) Lime Injection (LIMB)

2) Two Stage Slagging Combustors

3) Coal Water Slurry Combustion

4) Micronized Coal Combustion

5) Low NO_x Systems/Dual Fuel-Overfiring

B. Fluidized Bed Combustion: K. Yeager

Atmospheric Fluidized Bed Combustion

Pressurized Fluidized Bed Combustion

C. Lo BTU-Gas Airblown Gasifiers: Wm. McCormick, Jr.

o Post Combustion Emission Control: L. Papay

SO_x Removal

NO_x Removal

o Waste Management: E.S. Rubin

Drafts for all sections were exchanged between all members of the Panel to minimize overlaps and to bring to bear the maximum of experience available from the Panel to the entire field.

These individual reports are in Volume II. It is necessary to read each section to understand the subject and to obtain the view of the Panel. However, in order to give the reader a quick access to the major findings, they are presented in summary form in Section VII.

VII. SUMMARY RECOMMENDATIONS

o The total amount budgeted by DOE for FY 1986 in the field of Clean Use of Coal is about $57 million. The figure appears too small by comparison with the needs that the increasing use of coal implies. For ready reference, the following excerpts from the FY 1986 Fossil Energy Budget are noted here:

Coal Related R&D (Millions)

Subject	FY '85 Estimate	FY '86 Request
Control Technology & Preparation	$ 35.1	$ 27.2
Combustion Systems	30.2	29.2
Total: Coal (incl. above)	252.5	148.8

o Within the clean use of coal area the overall DOE program is well dispersed and all major technological areas are covered in some way. However, the budget does not allow DOE to help with the transfer of the new technologies to the private sector and to assure their commercialization. This is the result of basic policy which should be reconsidered.

In most instances, the current policy of abandoning a technology after Proof of Concept has been established will result in just that-- abandonment.

The subject of clean use of coal is of major near-term and long-term national importance and deserves a change in this policy. Specifically, DOE should assure commercialization by participating in the needed larger scale tests which are characteristic for utility operations before the technology can be adopted. Obviously, careful selection of projects and extensive private co-funding are a prerequisite. Specific examples of such projects are noted elsewhere in this report.

o As to R&D in Pre-Combustion (Coal Cleaning):

The DOE program has two distinct objectives: 1) to reduce SO_2 emission by removal of pyrite, and 2) to allow use of coal in lieu of oil or gas in systems designed only for the latter.

1) As to reducing SO_2 emissions, it will be important to continue comparing the cost of proposed advanced cleaning systems with the incremental cost of SO_2 reduction by other means, (LIMB, FGD, low sulfur coal, current commercial preparation process, etc.). Most of these costs are now well defined and do not allow the use of very costly cleaning systems. Somewhat higher costs might be justified if sulfur removal can be improved.

2) Displacing oil or gas with coal will require a particularly efficient removal of ash which can be achieved only by extensive comminution and separation of the coal from the mineral at sizes generally well below current practice. This will be expensive. However, the difference in the prices of coal vs. oil/gas allows a much greater cleaning cost than that for systems designed for SO_2 reduction in coal-fired units. It will also be important to determine the acceptable ash level by running large scale combustion tests; 1 to 2% ash may be acceptable. This seems within reach of new physical cleaning systems which DOE intends to explore jointly with the Electric Power Research Institute (EPRI) at the Homer City, PA Coal Cleaning Test Facility (CCTF). However, the cost of chemical cleaning, now one of DOE's key projects, will be very much higher (processing costs roughly equal to the cost of coal) and an independent feasibility study of the system is recommended based on results from the integrated unit now in start-up.

Finally, DOE is urged to place particular attention in its coal cleaning programs to those coal resources which represent the major U.S. reserves and which are most in need of new technology because they are all difficult to clean. These are the Indiana/Illinois #5 and 6, Kentucky #9 and 11, Ohio/Pennsylvania/West Virginia's #8 and 9 (Pittsburgh and Sewickley) seams. Too often R&D is carried out on coals that can be readily cleaned using existing technology.

o As to Conventional (Pulverized) Coal Combustion:

The subject was further subdivided to draw attention to this important area which represents by far the largest use of all coal now and in the foreseeable future.

1) Furnace Limestone Injection/Multistage Burners:

DOE is virtually absent from this area. This is unfortunate because LIMB is generally viewed (although not by all), as one of the potential SO_2 abatement systems which can be retrofitted, and which may be considerably less costly than FGD, though this is offset by the lower percentage SO_2 removal. However, it may still promise to reduce emissions up to 60%. There is hope, given added R&D, that this level can be pushed up significantly higher, allowing NSPS standards to be reached in some cases. An important R&D goal here will be reduction of any impact on boiler reliability and particulate controls that the process may have.

The program is mainly supported by EPA and EPRI. The Panel urges DOE to participate in this area. Specifically, this would involve test firing LIMB on a 100MW tangentially fired boiler which represents almost 50% of existing units (a wall fired test is already committed). In addition, R&D on improved sorbents and sorbent ash interactions is needed. DOE has outstanding competence in its several National Laboratories which could be brought to bear on this subject.

2) Slagging Combustors to Use Coal in Oil Fired Units:

This concept was in extensive use in the utility industry during the 1950s and 1960s but was discontinued mainly for environmental reasons (high NO_x). New combustion R&D has recently yielded an updated version of the slagging burner which is environmentally benign (low NO_x plus possible SO_2 reduction through limestone addition) while retaining the key feature of removing up to 90% of the ash from the main furnace. Furthermore, it is hoped that the new burner will be retrofittable. DOE is supporting this co-funded program on industrial boilers. If the initial results are positive, DOE should be encouraged to support larger capacity burner tests in the future.

3) Combustion of Coal/Water Slurry

DOE has a significant commitment in this area and has contributed very effectively to the initial combustion tests and CWS evaluation. CWS as a fuel is attracting considerable private sector attention because it opens the door to more intensive coal cleaning at the finer sizes (mainly PC grind: i.e., 80% under 200 mesh) which liberates additional minerals (see section on coal cleaning); CWS implicitly eliminates the costly step of drying the fine coal. Use of this CWS (70% pulverized ground coal) in oil/gas designed boilers would require substantial capacity derating. Use of CWS is also in the early stage of development as it applies to ultrafine (i.e., micronized to -325 micron) coal. CWS is a technology primarily aimed at replacing oil (particularly residual oil) with coal.

Acceptance of pulverized grind CWS by the utility industry will require further extended large scale combustion tests. The private sector seems to be ready to pursue this subject. However, the high cost of large-scale tests will require substantial DOE assistance.

4) P.C. Combustion of Micronized (-325 mesh) Coal:

Ultrafine grinding is an alternate concept suggested to permit firing of coal in oil-designed boilers without the penalty of capacity derating. A special problem is the high energy required for fine grinding. Evidently this system is being developed by the private sector without DOE involvement. Some test firing of dry micronized coal has been conducted on commercial scale boilers and it may become another useful technology for increased use of coal if the test program is expanded. As practiced, it had no impact on SO_2 emission except through the use of cleaned coal. Further demonstrations are planned with electrostatic cleaning after micropulverization. One specific configuration is the use of micronized coal in the form of coal/water slurry. However, the implication of CWS is broader and point 3), above, covers this subject.

5) Low NO_x Combustion Systems

This too is an area of importance where DOE is not currently involved as far as any near term retrofit systems are concerned. While NO_x can be reduced by ammonia injection and catalytic reduction in various configurations, this is a very costly step. DOE is exploring FGD systems to remove NO_x in its long range R&D program. The NO_x problem may, however, require some attention in the near term and development of modified (staged) burners offers substantial NO_x reduction (50-75%). Low-NO_x burner designs are nearing demonstration scale development by the several U.S. boiler manufacturers. Advanced combustion staging processes are also under development which offer the prospect for greatest NO_x reduction where applicable. One approach which has shown promise in tests conducted by Southern California Edison is use of a low nitrogen fuel (example methanol) for "over-firing". It warrants further tests.

o As to Fluidized Bed Combustion:

DOE has done an excellent job of encouraging this technology in the U.S. The atmospheric version has begun to receive good acceptance by the private sector both for new plant and even for retrofit by industry and the utilities. Demonstration units up to 160 MW capacity are being built. Thus, further direct support by DOE can be concentrated on certain ancillary problems such as R&D on sorbents and heat transfer in circulating beds operating under high fluidization pressure, etc.

The fluidized combustor can also be applied to pressurized systems where further important advantages may be obtained by shop fabrication and in terms of efficiency. Progress on these PFBC's will require considerable further support from DOE. At this time, DOE funds are mainly used to support to International Energy Agency (IEA) program at Grimethorpe, England, and it is important that DOE continue support for the remaining segment of this international project. Apart from the basic merit of PFBC, this project gives DOE a chance to rebuild its credibility as an international R&D partner, which was badly tarnished by some precipitous withdrawals from other projects. Grimethorpe is a PFBC-component test facility intended to yield engineering data for design of future pilot- or semi-works units.

Finally, DOE should also support the properly co-funded design, construction and operation of a pressurized fluidized bed boiler module for use in the utility industry. A target of a 100MW unit, based on circulating bed configuration, may be the most likely candidate.

- As to Air-Blown Gasifiers (Low BTU Gas):

The use of gasification as the initial step in the clean use of coal now constitutes the largest fossil fuel R&D project in the utility industry. The 100MW unit at the Cool Water Generating Station in California is based on pressurized gasification using oxygen. This process also represents a key step in virtually all conversions of coal to synthetic oil or gas. Synthetic fuel development is receiving extensive support in the U.S. and abroad and can be distinguished from the clean coal use program in spite of certain overlaps. For this reason, it was decided at the outset not to include it in the present study.

Conversely, the airblown version of gasification can be viewed as "two stage combustion, with intermediate gas clean-up" and implicitly as part of the clean use of coal.

This is one of the oldest processes applied to coal, and it was practiced in literally thousands of units all around the world from about 1850 to 1950. The equipment used in the past would not be acceptable today, but DOE has supported some recent tests using the latest version of the atmospheric fixed bed gasifier, which was the standard in earlier days.

The equipment is simple, low in cost and would find a market in certain industrial applications where the low heating value of the gas (140-180 BTU/scf) does not require major revisions of the user's equipment. Airblown gasifiers must be closely integrated with individual furnaces, etc. because the cost of piping over longer distances is prohibitive.

DOE may encourage the application of airblown gasifiers by supporting gasification tests to broaden the sizes and types of coal which can be used reliably, both in the fixed bed and the fluidized bed equipment now commercially available. Note that in the absence of low cost air preheaters, the fluidized bed is the only system that can directly gasify fine-sized coal using air (Winkler reactor). An interesting alternate is the Kiln-Gas process currently under development.

Most important, however, will be the ongoing DOE program for the clean-up of raw gas (including Lo BTU gas), preferably at elevated temperature. Emphasis by DOE has been on removal of particulates and alkalies to allow use of the gas in turbines. To capture a broader market would also require development of a low cost sulfur removal step. However, the cost margin available is narrow, making this a difficult target.

o As to Post-Combustion Emission Control Technologies:

This approach to clean-up is the mainstay of current control technology and is likely to remain so for a considerable time to come. It thus requires particular attention. The extent to which it has already penetrated the market and the forecast growth are given in Volume II, Section E. It can be retrofitted, space permitting, to virtually any combustion system, which adds to its importance. Above all, with costs now fairly well defined it remains the "standard" to which alternate systems must be compared.

With nearly 50,000 MW in operation, numerous activities are being conducted to refine these operations for the near term. The resulting improvements will make the systems more efficient and above all more reliable, but they cannot materially reduce the capital costs which generally range from $175 to 300/KW for retrofits (much higher costs are possible) and $110 to 175/KW for new plants, with a levelized cost of 8 to 25 mills/kwhr.

DOE should note that the long-term developing technologies, which make up the bulk of DOE investments in the Post-Combustion area, would apply only if emissions regulations (particularly for NO_x) were much more strict than at present (and thus may result in higher costs). This is true, for example, of the E-beam units piloted at the Tennessee Valley Authority's (TVA) Shawnee plant. The advantage sought in the simultaneous removal of both SO_x and NO_x is a more reliable and less labor intensive process that would reduce/eliminate the generation of solid wastes. For lower levels of NO_x removal, NO_x can probably be reduced more economically by combustion modification. As in other areas, DOE would have to extend its presence well beyond the proof of concept stage if any of these new SO_x/NO_x removal systems are to find commercial acceptance, and even more so if the economic attraction is not large.

At the same time, there is an urgent need for low cost, retrofittable flue gas control technology, even if some lower removal efficiency would result. This target requires increased attention by DOE. One potential approach is the injection of sorbent into the fluegas ahead of the bag house or electrostatic precipitator (ESP). To be acceptable, this requires a substantial increase in the DOE efforts on particulate removal, including R&D on the upgrading of existing ESP facilities. DOE should support full scale testing of such low-cost, retrofit systems in conjunction with EPA, EPRI and the utilities.

- As to Waste Management:

  Recent DOE efforts have been properly concentrated on characterization of wastes currently produced by the many operating plants and on a study of the potential impact of alternative disposal methods, particularly those which may be needed under RCRA. Current efforts to begin characterizing wastes from emerging technologies is a necessary first step to insuring that solid waste disposal problems do not pose unacceptable technical or economic barriers to new process development. Any reclassification of utility or other coal-related wastes (e.g., mining preparation) would have a significant impact on the required DOE clean use of coal program, but this is not foreseen as likely at this time. Increased efforts by DOE to co-fund programs aimed at waste utilization (rather than disposal) are recommended.

A. THE CLEANING OF COAL

by: William Poundstone and Edward Rubin

I. DEFINITION OF SUBJECT

Coal cleaning is the process by which impurities are removed from coal in order to reduce its mineral content and increase its energy content per unit mass. This is usually done by one or more mechanical processes which make use of differences in the physical properties of coal and mineral impurities (especially specific gravity) to accomplish the separation. Such processes are often called "physical" or "mechanical" coal cleaning. Where chemical changes in the coal are used to accomplish a separation, the process is called "chemical" coal cleaning. Coal cleaning can potentially play a role in achieving a number of DOE's stated goals or objectives. Current mechanical coal cleaning technology and equipment can:

- Reduce coal into two fractions: one having lower sulfur and ash content than presently washed coals, and able to be used in normal coal burning equipment; the other having higher sulfur and ash content, able to be burned in an environmentally acceptable manner in a new fluid bed combustor, with a consequent reduction in sulfur emissions. This approach would be economically attractive because it enables maximum BTU recovery to be achieved.

In addition, the new "super cleaning" process under development by DOE and by the private sector, which mechanically cleans coal after it has been crushed to very fine sized particles, can potentially :

- Reduce ash in coal to levels that will enable coal to replace oil in certain existing oil designed boilers.

- Make an even greater reduction in ash and sulfur with an economically acceptable BTU recovery.

New chemical coal cleaning processes can potentially:

- Make an even greater reduction in ash and sulfur than is possible with conventional cleaning or with the mechanical cleaning of finely ground coal.

- Make a coal product that can be used as an oil replacement fuel from a wider range of coals and in a wider range of applications than is possible with super mechanically cleaned coal. Chemical coal cleaning processes can remove organic sulfur and ash that cannot be removed by mechanical means, and can potentially allow coal to meet even New Source Performance Standards (NSPS).

The principal interest in super cleaning is to enable coal to be used as an oil replacement fuel. However, this concept would be used as a means of lowering sulfur emissions in conventional coal combustion if the process costs prove to be less than the cost of lowering sulfur emissions by other means such as flue gas scrubbing, or switching to an inherently low sulfur coal.

Most coal cleaning, until recently, was done for economic rather than environmental reasons, with the principal goal being to reduce the mineral matter (ash content) of coal. The degree of cleaning and thermal drying for moisture control has historically been determined by the need to achieve the lowest total cost for mining, transporting, and converting coal to other forms of energy. However, not all coals are, or need be, cleaned for economic reasons as the most favorable economics frequently can be achieved by selective mining (this is especially true in the case of surface mined coal).

Currently, there is a renewed interest in coal cleaning technology as a potential means of sulfur reduction for acid rain controls; as a means of allowing existing and new high sulfur coal sources to be used under current allowable sulfur emission standards; and as a way of establishing new markets for coal. While existing technology has not yet been fully employed, much attention is currently being directed to new processes to mechanically or chemically clean coal, which is first ground to liberate most of the mineral contaminates from the pure coal substance. Inherent in these new processes is the change in the nature of how the resulting finely sized clean coal must be handled. It appears that this "super cleaned" coal either will have to be cleaned at the point of use, or transported from the cleaning plant to point of use by some unconventional means such as in slurry form, or reagglomerated lump that can be handled as a conventional solid product.

II. STATE OF THE ART

Conventional coal cleaning as practiced today intentionally tries to keep the coal in lump form as it comes from the mine except that the largest pieces are usually limited to some convenient size (approximately six inches) by crushing. In general the mined material that is processed through a coal cleaning plant will contain the following:

1. Non-coal material (so-called partings and binders) that cannot be economically segregated and removed from the coal in the mining process.

2. Material from the non-coal strata (so-called overburden and underburden) that overlies or underlies the coal seam and is inadvertently mined with the coal.

3. Impurities in the coal seam, such as large pieces of pyrite ("sulfur balls") that break free from the base coal in the mining process or in the subsequent crushing that is done for convenient handling.

4. Coal containing various amounts of mineral matter finely dispersed throughout its pure coal matrix, as well as certain organic impurities such as sulfur and nitrogen.

Items 1, 2, and 3 are generally much higher in specific gravity than the coal (with its finely dispersed mineral matter) and can usually be separated from the raw coal mixture by conventional technology at a modest cost. The remaining mineral matter, especially pyrite, is not always uniformly distributed in the coal. A coal seam is usually made up of a number of beds of varying thickness that were deposited at different times. Much of the variation in coal quality is believed to stem from the variations in thickness of these beds. In addition, pyrite and other mineral matter occur in coal in differing size and shape particles. Because of this uneven distribution some pieces of coal will have a somewhat higher specific gravity than others, and can thus be separated into fractions containing less than average and more than average mineral ash. Unfortunately, in most coals only a modest improvement in quality can be made by lowering the specific gravity used in the cleaning process without suffering a prohibitively high cost associated with the loss of heat value in the rejected material. Consequently, conventional coal cleaning practice generally does little to remove the mineral matter that is finely dispersed throughout the coal matrix.

The cost of coal cleaning has three components:

- Operating and maintenance costs (labor, power, and supplies).
- Capital cost (the cost associated with the investment in cleaning equipment)
- The cost associated with the loss of heat value of the material discarded. This cost is incurred because of two types of losses. One is the loss of clean coal due to the inefficiency of the process and due to the inability to recover all of the extremely fine coal particles from the water used in the cleaning process. The other is the loss of heat value associated with the impurities removed in the process. Typically these impurities will have a heating value of from 2000 to 4000 BTU per pound (BTU/lb), or roughly 20 to 30% of the heating value of clean coal. Even shale and pyrite rock have heat contents that typically exceed 1000 BTU/lb.

It is much easier and less expensive to clean the lump coal than the small particles. This is because most cleaning today is done by systems that use water that must be removed from the clean coal as well as from the rejected material. Lumps have relatively small surface area per unit of weight compared to fine sized particles. Lumps can be dewatered or dried rapidly by mere draining on a screen, whereas the small pieces have sufficient surface area that they require more expensive technologies to remove or reduce the surface moisture. The slower rate of settling of fine sized particles in a liquid also adds to the difficulty and the cost of fine coal cleaning where liquids are used in the separating process.

The most commonly employed cleaning processes use water or water and magnetite (heavy media). However, some coal is also cleaned using air tables. Generally, different size fractions of coal are cleaned in separate devices. The lump sizes (typically larger than 3/8 inch) are usually cleaned in a Jig or in a heavy media vessel. The intermediate sized (typically less than 3/8 inch in size but larger than 28 mesh) are usually cleaned on Diester tables, water only or heavy media cyclones, or in a "Batac Jig". In total, about a third of the coal produced in this country is cleaned in some degree (beyond simple breaking and crushing). Coal washing is applied mostly to underground production, of which about 60% is washed, while less than 20% of surface-mined coal is cleaned before use. Washing is used for nearly all metallurgical coal, while approximately 20% of all utility steam coal is washed for ash or sulfur removal.

In general, the western low sulfur coals are not washed since they are quite low in ash and sulfur as mined. Underground mined coal is more frequently washed than surface mined coal because it is more likely to be contaminated with rock from adjacent strata. Today there is a trend toward more coal cleaning because of the demand for coals of lower sulfur content. At the same time, there is also a trend toward increased coal recovery because the value of coal today has reached the point that coal as fine as minus 28 mesh is rarely discarded as was the case 20 years ago. In the past, it was frequently cheaper to discard the fine sizes and mine additional coal in its place, rather than clean this size fraction.

Currently, the lowest cost means of significantly reducing sulfur emissions for a given coal is through the use of flue gas desulfurization (FGD) or FGD in combination with some form of coal cleaning. The lowest overall cost of sulfur reduction results when the mining process employs mining methods and cleaning processes that have costs per unit of sulfur reduction less than the incremental cost of sulfur removal via flue gas scrubbing. Not all high pyrite coals used for power generation are currently cleaned and some are only partially cleaned, but the trend is clearly toward more comprehensive coal cleaning.

The current practice in cleaning for coals used for heat energy (thermal coal) is to clean it in lump form essentially as it comes from the mine, which is the least expensive approach. However, if we are to remove pyrite and other impurities we must first separate or "liberate" these materials from the coal. This is usually done by crushing prior to cleaning or, in the case of raw coals containing clay materials, crushing after some precleaning. The mechanical cleaning of finely ground coal ("super cleaning") can potentially remove a higher percentage of pyritic sulfur and can make significant additional reductions in the mineral ash of many coals. Since low sulfur coals contain little or no pyritic sulfur, physical cleaning processes will be of little help in reducing sulfur in these cases.

III. OUTLOOK FOR REQUIREMENTS FOR 2020

It is difficult to forecast with any precision the use of new coal cleaning technology in the coming years because its use depends upon:

o The success of new coal cleaning processes and their resultant cost.

o The changes, if any, in environmental laws and regulations covering the allowable emissions of sulfur and other contaminants associated with the burning of coal and the disposal of its waste materials.

o The changes, if any, in the environmental laws and regulations covering the use of other sources of energy that compete with coal.

o The availability and the cost of oil and gas.

o The degree of improvement and the future cost of FGD, LIMB and other alternative means of reducing sulfur emissions.

It seems likely that coal cleaning will be less expensive than FGD in many locations if the desired reduction in sulfur emissions is moderate. It also seems likely that at least some portion of the current oil market will be replaced with coal, possibly in the form of coal water mixture fuels made with coals that have been cleaned after being finely ground.

Together, the potential applications of improved coal cleaning systems constitute a very substantial market (ultimately several hundred million tons per year) and thus warrant diligent pursuit.

IV. CURRENT R&D

The overall goal of the DOE research and development program in coal preparation is to develop the technology to reduce the ash and sulfur content of US coals so that the product can be formulated into a high quality fuel that could replace oil and/or natural gas in both new and retrofit applications. Thus, a successful R&D program would allow coal to penetrate markets currently dominated by other (typically cleaner) forms of fossil fuel. At the same time, the R&D program seems not adequately directed toward the solid coal fuel market as it currently exists (i.e., coal-fired power plants and industrial boilers). However, this very much larger and more significant market also would benefit if the economics of new cleaning technology proves favorable.

The DOE coal preparation program may be viewed in terms of four major components: (1) physical cleaning processes; (2) non-physical cleaning processes; (3) ancillary operations; and (4) coal characterization. As a fraction of the total FY85 budget request of $11.15 million for coal preparation, these areas amount to 49%, 31%, 13%, and 6%, respectively. Brief summaries of current R&D programs in each are provided below, including some processes also being developed in the private sector.

1. Physical Cleaning

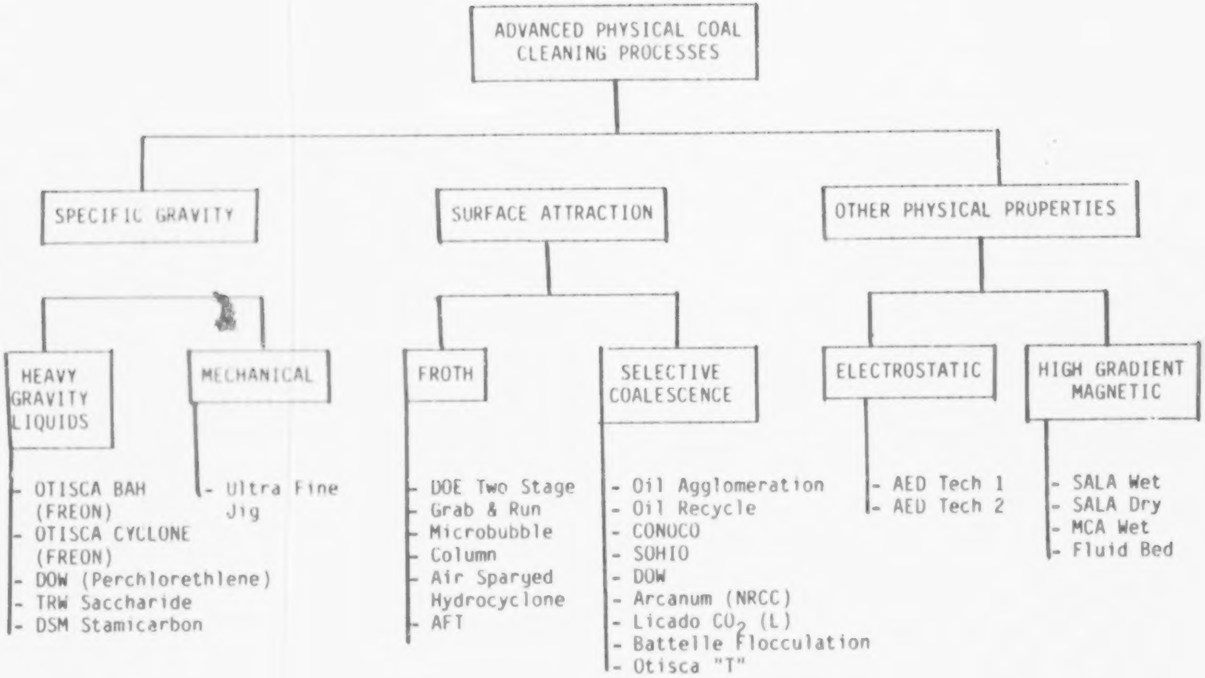
Figure 1 provides an overview of advanced physical fine coal cleaning processes under development at this time. Current R&D in physical coal cleaning is directed to removing pyrite and mineral ash after the coal has been crushed--frequently to smaller than 200 mesh size. While coals differ in the size and form in which the pyrite (and other mineral ash) occur, it is possible to separate up to about 80% of the pyrite from some coals after grinding to "pulverizer" size (80% minus 200 mesh). There are a great number of processes under study by DOE and the private sector that accomplish the separation after crushing. These processes can be grouped into three types:

A. Those that work on differences in specific gravity.

B. Those that work on differences in surface attraction through selective coalescence. Both agglomeration and froth flotation processes function because of differences in surface attraction.

C. Those that work on differences in other physical properties. These include high gradient magnetic separation and electrostatic separation devices.

FIGURE 1


ADVANCED PHYSICAL COAL CLEANING PROCESSES
SPECIFIC GRAVITY
SURFACE ATTRACTION
OTHER PHYSICAL PROPERTIES
HEAVY GRAVITY LIQUIDS
MECHANICAL
FROTH
SELECTIVE COALESCENCE
ELECTROSTATIC
HIGH GRADIENT MAGNETIC
- OTISCA BAH (FREON)
- OTISCA CYCLONE (FREON)
- DOW (Perchlorethlene)
- TRW Saccharide
- DSM Stamicarbon
- Ultra Fine Jig
- DOE Two Stage
- Grab & Run
- Microbubble
- Column
- Air Sparyed Hydrocyclone
- AFT
- Oil Agglomeration
- Oil Recycle
- CONOCO
- SOHIO
- DOW
- Arcanum (NRCC)
- Licado CO_2 (L)
- Battelle Flocculation
- Otisca "T"
- AED Tech 1
- AED Tech 2
- SALA Wet
- SALA Dry
- MCA Wet
- Fluid Bed

High levels of ash and or pyrite removal have been achieved in the laboratory on coals crushed to 200 mesh on a limited number of coals. However, the economic merit of most of these processes are not clear as they have not yet been tried on commercial sized equipment. Scale-up to the "proof-of-concept" state is expected in the 1985-1988 period.

A. Separation by Specific Gravity

Some of the new processes that use specific gravity as a means of separation involve low boiling point "true heavy gravity liquids" such as freon and perchlorethylene. Since the interest in these processes is applied to fine coal, cyclones are typically used instead of a static vessel in order to speed up the separating process. The process liquid is recovered for reuse by heating the wet clean product above the boiling point of the liquid used and recondensing the vapor. These processes can make relatively sharp separations and do not require the expensive water removal process, but may prove to have difficult environmental problems associated with the escape of vapor from the process equipment and from traces of liquid which are lost with the solid streams leaving the process.

Another new specific gravity process is the "ultra fine" or "slimes jig". This device is designed to process minus 28 mesh material by using a more rapid jigging or pulsing action. Indications are that this device can effectively separate finer sized particles than is possible in the fine coal jigs currently in common use throughout the world for cleaning coals of minus 10mm (less than 3/8 inch).

B. Separation by Surface Attraction

There is much research underway on processes that use the selective coalescence of fine coal particles in a liquid medium. Various of these processes use either oil, liquid freon or liquid carbon dioxide as the agglomerating agent. Each of these liquids has an attraction for clean coal and is not attracted to shale, clay, and certain other contaminates. Unfortunately, pyrite normally behaves like the clean coal and is attracted to the same liquids. Consequently, it must be separated by some other means if the amount present dictates removal. There is some indication that these processes may be less precise in separating efficiency than true heavy gravity liquid, and are likely to be better ash removers that sulfur reducers.

C. Separation by Other Physical Properties

Since pyrite and even shales are more magnetic than clean coal, very high strength magnets may be used as a means of coal cleaning. In addition, a new electrostatic process is currently being tested on a commercial size unit at a power plant in Ohio. In this approach, fine coal (essentially bone dry) that has gone through the pulverizer at a power plant is given an electric charge and placed on the surface of a charged rotating drum similar to the ones used to clean taconite iron ore. The difference in the dielectric properties of clean coal and impurities (pyrite and ash particles) causes the impurities to fly off the drum as it passes a second electric charge while the coal continues to cling to the drum until it is scraped off after the drum has rotated another quarter turn. However, the finely ground material to be cleaned must be placed on the surface of the drum in a layer that is only one particle thick and the capacity (and hence the cost) of a single drum is directly influenced by the particle diameter. There is also some indication that the separating efficiency is such that more than one pass may be needed to avoid high BTU losses in cleaning.

A new program to start in FY85 is a joint program between DOE and the EPRI to promote the development and testing of advanced physical cleaning concepts using EPRI's Homer City, Pennsylvania Coal Cleaning Test Facility. The Program will solicit proposals for new concepts to achieve high removal of impurities from finely crushed coal (28 mesh by 0), to be tested at a 1 ton/hr scale. Initial projects are to be selected late in FY85.

2. Non-Physical Cleaning

To obtain still higher degrees of sulfur removal, a number of non-physical process approaches to removing organic sulfur are being pursued. Figure 2 shows the various types of chemical and biological cleaning processes that have been pursued by both the public and private sectors. The centerpiece of the DOE R&D program in this area is a chemical cleaning process (Gravimelt) which employs a molten alkali salt to achieve the removal of more than 90 percent of all organic and pyritic sulfur and even higher levels of ash removal. The process concept has been successfully tested in the laboratory and is now being expanded to an integrated continuous 20 lb/hr bench scale unit. Plans also are being formulated to design a continuous fully integrated system at the "proof-of-concept" scale (500 lb/hr or greater). Current economic studies indicate processing costs of about $35-$55/ton of clean coal. This would more than double the current F.O.B. cost of typical US utility coals, and would generally be uncompetitive with conventional FGD systems, whose cost is approximately $25/ton of coal for typical new utility applications. Thus, chemically cleaned coal (or derivative fuels) would most likely be viewed as a substitute for oil or natural gas, where the economics appear to be closer to being competitive.

Another alkali-based chemical cleaning process currently being supported employs microwave radiation to achieve lower process residence times. This scheme is still at the laboratory scale and has not yet been tested in an integrated system.

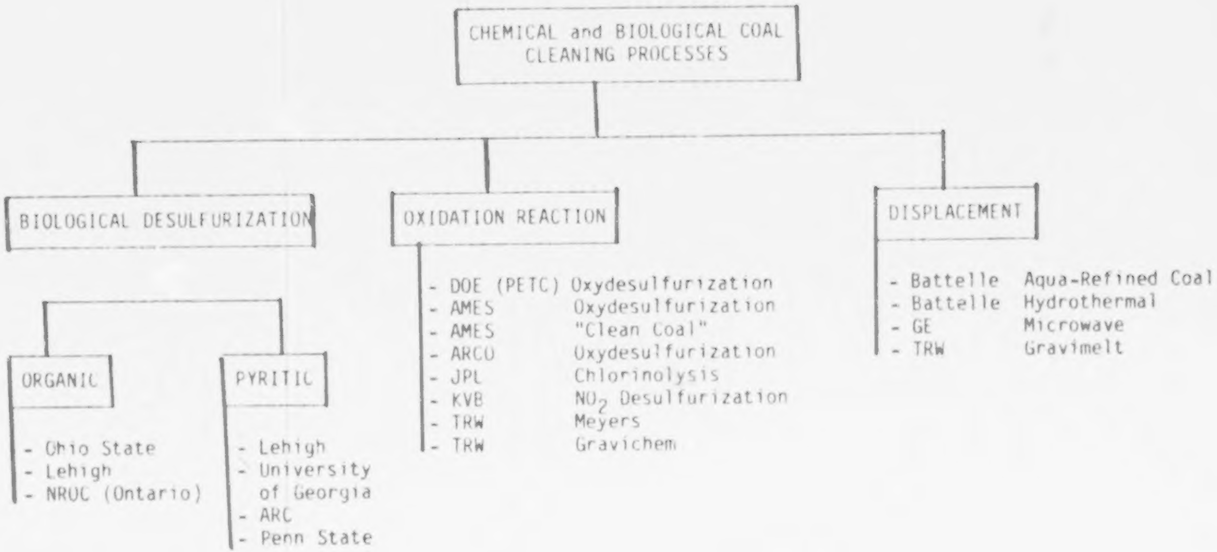
A third approach being explored for organic sulfur removal is microbial desulfurization. The concept is to develop "bugs" that can biologically remove sulfur from finely crushed coal. This project too is still being evaluated at the laboratory scale.

DOE also is beginning to look at the feasibility of beneficiating chemically conditioned coals to improve their grindability and other physical characteristics. One external project is underway and another is scheduled to begin this year.

Ancillary Operations

Methods for dewatering and drying ultra-fine sixed coal (less than 325 mesh), as well as low rank (sub-bituminous and lignite) coals, are being pursued as part of R&D on ancillary operations. There is also a project on the ultrasonic communition of coal which holds the promise of achieving fine coal particle

FIGURE 2


CHEMICAL and BIOLOGICAL COAL CLEANING PROCESSES
BIOLOGICAL DESULFURIZATION
ORGANIC
- Ohio State
- Lehigh
- NRUC (Ontario)
PYRITIC
- Lehigh
- University of Georgia
- ARC
- Penn State
OXIDATION REACTION
- DOE (PETC) Oxydesulfurization
- AMES Oxydesulfurization
- AMES "Clean Coal"
- ARCO Oxydesulfurization
- JPL Chlorinolysis
- KVB NO_2 Desulfurization
- TRW Meyers
- TRW Gravichem
DISPLACEMENT
- Battelle Aqua-Refined Coal
- Battelle Hydrothermal
- GE Microwave
- TRW Gravimelt

sizes with substantially lower power requirements than conventional technology. This project has been tested at the laboratory scale and will now be scaled up to a 1 ton/hr proof of concept stage.

Coal Characterization

This is the smallest element of the DOE R&D program. Its purpose is to characterize the sulfur and ash reductions that may be possible for selected Appalachian coals ground to ultra-fine sizes. This represents an extension of earlier work by the US Bureau of Mines to develop an extensive data base of washability characteristics for US coals. Additional aspects of the coal characterization program are concerned with trace elements analysis, organic sulfur studies and enhanced sulfur liberation due to ultrasonic communition.

Coal-Water Mixture Fuels

Separate from the R&D Program on coal preparation is a DOE program on the utilization of coal water mixture (CWM) fuels, details of which are described elsewhere in this report. The goals of the coal preparation program, however, are closely related to CWM in that coal water mixture fuels currently represent one of the key vehicles for utilizing super-clean coal as an alternative to oil or gas. The CWM research program is concerned not only with technical aspects of slurry preparation, stability and rheology, but also with combustion characteristics in various types of end use devices. The DOE program structure, however, does not provide for the horizontal integration of projects in the coal preparation and CWM combustion, including fine particle emissions and the fate of stabilizing and surfactant additives, also remain to be characterized.

V. COMMENTS ON R&D PROGRAMS

The DOE's research program on coal cleaning seems to contain all of the elements necessary to address the subject. Work includes studies to determine the potential of various coals for deep cleaning, basic coal surface investigation, research on coal comminution (coal crushing), research on the handling and use of super clean coal as a slurry and as a ultra-fine dry product, experimental combustion tests, research on pelletizing and other means of reagglomeration, as well as work on a number of mechanical, chemical and biological cleaning processes.

The DOE program goals for coal cleaning are to find economical means of further reducing sulfur dioxide emissions from coal burning, and to reduce the ash content of coal so that it may become a viable replacement for oil fuel. The price that we can afford to pay to achieve these goals is well defined. For direct coal combustion systems, the goal of reducing sulfur emissions via coal cleaning can be achieved only if the cost of the new cleaning processes are competitive with the cost of existing alternative approaches such as coal switching and FGD, and of new developing technologies such as LIMB. The goal of enabling coal to become a viable oil substitute is an easier target to estimate as the competitive price of super cleaned coal used for oil applications can approach--but not equal--the price of oil.

Each coal and each application is likely to have different costs, thus, it is difficult (and potentially misleading) to present specific cost numbers. However, it is our belief that the target cost for sulfur reductions from coal combustion systems is likely to be in the range of $200 to $500 per ton of sulfur dioxide removed for most applications where the reduction required is from 20% to 50%. These cost and percentage reduction amounts include both fuel switching and the assumption that LIMB and similar new technologies will be developed commercially. These costs per ton of sulfur dioxide removed translate into costs of $4 to $10 per ton of coal (based on a 3% Pittsburgh Seam coal and a reduction of 1% by super coal cleaning). This establishes the target range of costs for any new system used to reduce SO_2 emissions.

Various estimates have been made of the costs that can be expended to clean coal if it can replace oil as a fuel. Again, the target cost for each application is specific to the amount of boiler derating, the base coal cost, the cost of added capital, and the increased operating costs associated with handling additional ash and particulate matter, etc. These estimates are typically $35 per ton of coal, or some 3 to 9 times higher than the likely cost of meeting the moderate sulfur reduction goals for direct coal combustion.

An examination of some of the component costs of physical super coal cleaning may be useful in addressing this subject. Grinding to pulverized coal (PC) size (80% minus 200 mesh) is a key part of most if not all of the proposed new processes. While this is a significant new cost to the coal cleaning process, it is a cost that is currently being incurred by the coal user. Consequently, the total cost of mining, grinding, cleaning and burning coal will be little changed if the grinding is done at a location other than at the power plant, except for the higher cost of electricity and differences in the percentage operating factor (which could be better or worse than the current practice). If a water based cleaning process is used to clean coal after grinding to PC size, we can expect to incur a cost for additional thermal drying. Coal of this size can be mechanically dried to about 30% surface moisture or some 25% higher moisture than normal run of mine coal. The current cost of evaporative drying (not including the cost of mechanical dewatering) is roughly $15 to $20 per ton of water removed (including a capital charge). The drying cost alone for PC size coal that has been water cleaned can be expected to be in the order of $4.20 to $5.60 per ton of coal.

If true heavy gravity liquids having low boiling points are used to clean coal that has been ground to PC size, we can expect to recover something less than 100% of the liquid used in the process due to losses to the atmosphere and losses due to liquid retained in the coal. If the amount lost is only 1/10 of one percent of the weight of the cleaned coal, and the cost of the liquid is $1.00 per pound, the cost associated with this loss will be $2.00 per ton. In any cleaning process some coal energy (heating value) also is lost. A theoretical recovery of 90% to 95% of the total energy would be about the highest possible if large ash reductions are to be achieved. If we start with a $30 coal and assume a recovery of 90%, the cost associated with the energy lost with the cleaning plant refuse (not including plant capital or operating cost), will be $3.00 per ton of raw coal. Also associated with cleaning processes are capital and operating costs in addition to the cost associated with loss of heating value. If the coal is cleaned after grinding to PC size the cost of refuse disposal is likely to be higher than for washing a more conventional sized coal. The current capital and operating costs for a large new cleaning plant would typically be $3.00 to $4.00 per ton. Unless a new extremely fine coal cleaning process is very clever it is likely to cost more than a current technology plant that processes a conventionally sized coal.

From the foregoing discussion it can be seen that the goal of finding a new coal cleaning process that can significantly reduce the sulfur content of a given coal at a cost that meets our target cost ($4 to $10 per ton) will be a difficult challenge if the coal must be ground to PC size in order to liberate or free sufficient pyrite from the coal to permit the needed sulfur reduction. It is also apparent that the water-based systems have an especially tough job unless the coal is to be burned as a coal water slurry in an application where savings in handling and/or storing can offset some of the cost of coal cleaning. It would appear that the processes that work on dry pulverized coal have significant advantages if they can achieve good separating efficiencies (perhaps using multiple passes of the process) at acceptable capital costs. It is also evident that the target cost for coal cleaning for oil replacement is much easier to achieve and does not preclude any of the approaches currently being pursued. However, the key to meeting this goal will be the need for maximum ash reduction. It would seem that this requires the process to work on very fine (perhaps even finer than PC grind) coal, and to make very efficient separation.

Chemical coal cleaning seems to be the most difficult and highest risk of the various research undertakings. While this approach should be able to achieve the highest degree of ash and sulfur reduction its costs are likely to be higher than the physical cleaning schemes. Thus, we should examine where it has a chance of improving upon the other processes. With respect to sulfur removal, it seems unlikely that for modest sulfur reductions (20% to 50%) chemical cleaning can compete with a $4 to $10 per coal ton figure. The better chance would be for new plants where chemical cleaning could meet New Source Performance Standards by removing 90% of the sulfur, potentially competing with FGD. Here, however, the cost is a fairly well established (approximately $25 per ton of coal) and current estimates of the gravimelt process, for instance, are well in excess of this figure. Thus, chemical coal cleaning has a hope of being competitive principally in oil replacement applications, especially if world oil prices increase. The real issue is how low the coal ash must be to enable it to be used in a significant portion of the existing oilfired boiler market, and whether these levels can be achieved with physical coal cleaning alone at much less cost. This is not known at present, but many of the combustion experts have suggested that ash levels of 2% may be practical. Several of the companies developing new physical cleaning processes report obtaining ash levels of 1% to 2% range on certain coals in the laboratory. If 2% ash coal can be widely used in oil boilers, and if these ash levels can be obtained by physical cleaning means, there may not be a market for chemically cleaned coal if its costs are as now projected.

VI. CONCLUDING COMMENTS AND RECOMMENDATIONS

The following suggestions may be helpful in further improving the DOE program:

1. Much of the Congressional interest in new coal cleaning processes is based on the hope that they may be a means of further reducing sulfur emissions without massive fuel supply disruptions and the consequent impact on labor. It is thus important to make sure that the high sulfur coals that can be mined at relatively low cost (but which are likely to lose their market if further reductions in sulfur emissions are required) be included prominently in the test work. This would include coals from several areas of such seams as the Illinois and Indiana #5 and #6 seams, the Kentucky #9 and #11 seams and the Ohio, Pennsylvania and West Virginia Pittsburgh and Sewickley seams. There is a tendency of researchers in this field to work on the easiest-to-clean coals. These often are coals sufficiently low in sulfur and ash after conventional cleaning that they can be used in existing markets. The basic goal of the research will not be achieved unless we can apply these new processes to the higher sulfur coals that constitute the greatest reserves and which are likely to need help to remain marketable.

2. To facilitate the full-scale use and commercialization of research results, DOE should continue to actively seek private sector involvement in the development of improved coal cleaning technology, especially as it relates to sulfur removal applications in the bulk use of coal in industrial and utility boilers. DOE also may wish to study the role of tax treatment or other measures which may provide incentives for commercialization of low-cost sulfur removal methods based on coal cleaning in much the same way that incentives currently are offered for other types of pollution control technology.

3. After a new cleaning process has been demonstrated on a small scale and the key operating data have been collected, a comprehensive projected cost study of a commercial sized application should be made to assure that it has a chance of economic viability before large sums are spent on full-scale demonstration. These studies should ideally be made by people who have substantial experience in the design, building and operating of commercial coal cleaning plants. As a minimum requirement these economic studies should be carefully reviewed by individuals with commercial experience. In the past, some cost studies have been made by persons who lacked sufficient background for the job, and the studies were of limited help in knowing if the process was worth pursuing. In this area of research, many processes will work (both with respect to mechanical as well as chemical coal cleaning), but things that work are not necessarily economically viable. All of these processes compete within well-defined cost limits established by either the cost of oil, the cost of alternative low sulfur coals, or by the cost of flue gas desulfurization in its various forms. Thus, we should not pursue processes unless they offer realistic hope of being competitive, at least within some reasonable time frame. In coal cleaning research, the quality of the economic assessment may well be the most important part of the program and should receive the utmost attention.

4. Fundamental research on coal and its properties should be continued. In this area, the electron microscope may be helpful in assessing the cleaning potential of the various coals. If information on the size of pyrite and mineral ash particles as determined by this technique could be correlated with conventional float and sink tests, it would provide a faster and lower cost rough means of assessing the potential for coal cleaning for a given type of coal.

5. The planned DOE program should be carefully compared with past, present and planned private sector coal cleaning activities to avoid duplication of effort and to achieve program goals at lower costs.

6. Table 1 suggests the total estimated level of R&D funding needed for coal cleaning projects over the next five years (1986-1990). This includes private as well as public support, including some larger-scale projects for which DOE's contribution would not exceed 50%.

TABLE 1

ESTIMATED FUNDING REQUIREMENTS FOR COAL CLEANING R&D*
(MILLIONS OF DOLLARS)

AREA/YEAR	86	87	88	89	90	TOTAL
PHYSICAL CLEANING PROCESSES	10	10	12	15	15	62
CHEMICAL AND OTHER PROCESSES	5	5	7	10	10	37
ANCILLARY OPERATIONS	3	3	5	5	5	21
TOTAL	18	18	24	30	30	120

*Total estimated expenditure for public and private sectors.

B. COMBUSTION

I. PULVERIZED COAL COMBUSTION

By John Landis and Frank Princiotta

1. INTRODUCTION

Despite the current surplus of oil and gas, there is considerable interest among industrial and utility fuel consumers in further reducing their dependence on foreign energy supplies by using coal. Environmental and cost concerns have resulted in significant efforts to develop new and more effective ways of burning coal both in existing coal fired boilers and as a replacement fuel in boilers currently burning oil or gas. Such means include new coal fuel forms (e.g., slurried and micronized) and advanced combustion systems, such as slagging combustion, lime injection, and NO_x suppression.

Five near-term coal technologies are discussed:

- Dry micronized coal
- Coal-water slurries (with conventional pulverized grind and micronized grind coals)
- Two-stage slagging combustor
- Limestone injection with multistage burners (LIMB)
- Low NO_x systems/dual fuel overfiring

These technologies achieve clean coal use by two approaches: precombustion cleaning integrated in the preparation process for the two new fuel technologies and adjustments to the combustion phase in the others. These technologies are described along with their applicability and status of development. Also presented are proposed development programs including costs and schedules.

2. MICRONIZED COAL COMBUSTION

This section discusses the near term potential of burning dry micronized coal in boilers designed for oil and gas. This fuel offers a potential means for using coal as a substitute fuel in oil/gas designed boilers in an economically and environmentally acceptable manner and with a minimum derating of plant capacity. Grinding the raw coal more finely releases ash materials and sulfur compounds, permitting more effective separation by available coal cleaning methods. This fuel technology permits tailoring the fuel specification to the site-specific boiler in a way that cost optimizes the combination of coal cleaning, fine grinding, and plant capacity derating.

Background

Following is a discussion of the problems and potential for burning coal in boilers originally designed for oil and gas. It emphasizes how boiler design differences depend on fuel type and how coal preparation (including combinations of coal cleaning and finer grinding) for dry and coal water slurry fuel forms will permit coal to be used in oil/gas designed boilers in an economical and environmentally acceptable manner and with a minimum derating of plant capacity.

Boiler Characteristics

Boilers originally designed for coal can frequently be reconverted to this fuel. However, in many cases, the boilers were designed to burn oil or coal, with little expectation they would ever use coal. As a result these boilers are often too small to burn coal without considerable modifications or capacity derating. Furthermore, many boilers designed in the 1960s and 1970s have only oil or gas capability and are not compatible with conventional pulverized coal or stoker firing. Due to their relatively recent vintage, these boilers are unlikely to be retired and, unless new ways are found to convert them to coal, their demand for more expensive fuels will continue.

Boilers designed for coal are intrinsically different from their oil or gas designed counterparts. These differences can have a significant effect on combustion characteristics when an alternative fuel is burned. Typical oil-designed boiler differences are discussed below.

The overall dimensions of an oil designed boiler are considerably smaller than a coal boiler of comparable capacity. Heat release rates for oil boilers may be as high as 35,000 BTU per cubic foot compared to 20,000 or less for a coal-fired boiler. This difference is reflected in a smaller furnace volume. Furthermore, gas temperatures leaving the furnace can be much higher when a boiler is designed for oil. In a coal designed boiler, the upper portion of the furnace must provide sufficient radiant heat transfer surface to reduce gas temperatures to as low as 2000°F. The value is determined for each case by the coal's ash fusion temperature. High flue gas temperatures will allow carryover of molten ash, which is then deposited on relatively cool boiler tubes or walls. Because oil contains minimal quantities of ash, much higher furnace exit gas temperatures can be accommodated and oil-firing boilers are designed accordingly.

The configuration of the furnace bottom is also important. Stoker-fired boilers include the means for introducing combustion air and for removing the unburned ash. Pulverized-coal boilers typically have a deep hopper formed by the water walls of the boiler and a wet bottom ash removal system. Oil-fired boilers may have a flat or shallow sloped bottom with no provision for continuous removal of ash. Ash can be removed only during a boiler shutdown. The boiler may be installed with limited head room between the flat bottom and the boiler house floor, making modification difficult or impossible.

A third major difference relates to the configuration of superheater and economizer tubes in the convection passes of the boiler. Typically, coal-fired tubes are arranged to minimize the possibility of ash deposition or bridging of ash deposits between tubes. In many existing coal designed boilers, radiant tube spacing may be as large as 26 inches in the first bank of superheater tubes. In successive sections, the spacing is reduced as the flue gases are cooled and deposition problems are minimized. However, in an oil designed boiler, radiant tubes may be spaced at 6 inches or less and the convection tubes may have only 2 inch spacing. Furthermore, a staggered arrangement of tubes may be used to improve the contact of flue gases with tube surfaces. Finned tubes may also be used in economizer sections. Staggered or finned tubes in a coal fired boiler increases the likelihood of ash fouling and erosion.

Gas velocities through the convection sections may be significantly different. For a coal-fired boiler, it is common to limit velocities to 60 ft/s or less to minimize erosion by hard, refractory-like particles of ash. In an oil designed boiler, velocities of 100 ft/s or more can be encountered.

A final point relates to space restrictions for balance-of-plant equipment. Particulate collection equipment is always required at the back end of a coal-fired boiler. Fans may be larger than those required for an oil-fired boiler due to excess air requirements. Ash removal systems occupy valuable space around the boiler. Coal-unloading and storage facilities for a coal-fired boiler occupy significantly more land area than equivalent oil tankage and transfer facilities. Coal bunkers, pulverizers, and pneumatic transport systems are bulkier than their oil-handling counterparts. Oil-fired boilers are often "shoehorned" into plant arrangements, allowing little flexibility for future alterations.

Impact of Pulverized Coal on Oil Designed Boilers

The dimensional differences between coal designed boilers and oil/gas designed boilers can result in significant impacts when the latter are converted to coal. The important impacts include:

- Tube bank erosion - Combustion of conventional pulverized coal results in a large increase in ash loading in the flue gases. Due to their relatively large sizes, ash particles separate from the flue gas when an obstruction such as a convection section tube is encountered. At the high velocities found in oil or gas designed boilers, erosion of the tubes would occur.

- Inadequate furnace residence time - Pulverized coal burns more slowly than either oil or gas and, therefore, cannot attain complete carbon burnout before it passes into the convection section. FUrthermore, the flame can impinge on the tubes, increasing the potential for slag deposition and more frequent tube maintenance.

- Insufficient radiant heat transfer - Because the oil or gas designed furnace is smaller than that required for coal, there is insufficient radiant heat transfer surface. This may result in reduced steam generating capacity or increased gas temperatures, and therefore increased slagging and fouling.

- Ash removal problems - The flat or shallow sloped bottom does not allow large ash particles or slag deposits that fall from the tubes to be easily removed. Extensive modifications may be necessary to remove bottom ash. Furthermore, wall deslaggers may be required to control deposits on the furnace walls.

- Inadequate space - Auxiliary systems for coal storage and handling and for ash removal can occupy large amounts of space. Boilers not designed for coal firing may not have the space necessary for conversion to coal.

These impacts of converting oil/gas boilers to coal firing result in three types of problems. In some cases, the conversion may be simply infeasible; for example, lack of space may prevent conversion. In other cases, the problems may be technically solvable, but the solution is uneconomical. Finally, it may be necessary to significantly derate the boiler to (1) reduce gas velocities to allow more complete combustion within the smaller furnace and (2) to lower gas temperatures to reduce slagging and fouling.

Here we focus on the third type of problem, i.e., derating of boiler capacity and how to minimize it. Derating is the inability of the boiler to reach its rated capacity. This can result from a requirement to reduce the rate of fuel feed to meet a furnace-boiler design limit or from the inability of auxiliary equipment, such as fans, to maintain required performance. Derating should be distinguished from efficiency losses, which can be costly, but may not prevent the boiler from meeting its required load. Derating can create significant problems in locations where boiler capacity is limited. Depending on the specific boiler design, deratings of up to 50% or more have been projected for conversion to coal-based fuels. The need to minimize boiler derating has led to considerable research and development in advanced fuel and combustion technologies. These include micronized coal in dry and coal water slurry forms and the two-stage slagging combustor.

With micronized coal, higher combustion intensities produce shorter flame lengths, which can be accommodated in the smaller furnace volume of oil/gas designed boilers. In addition, the particle size of fly ash in the furnace is reduced, which results in fly ash entrainment in the flue gas stream and minimal deposition. Micronized coal achieves these results by a combination of coal cleaning and finer grinding before combustion.

Dry Micronized Coal Development

Recent laboratory and large-scale demonstration tests of the concept of using micronized coal for oil and gas fired boilers were sponsored by the Institute of Gas Technology (IGT), Gulf States Utilities (GSU), and Mississippi Power and Light Company (MP&L).

Micronized coal fuels are characterized by grinding coal finer than in pulverized coal operations. Programs to use coal in internal combustion engines have considered particle sizes as small as a few microns. However, for use as a boiler fuel, a much more moderate degree of fineness is considered acceptable. For a site specific application, the maximum particle size that could be tolerated with soot blowing would be specified. For purposes of this paper, micronized coal is defined as coal with a nominal top size of 325 mesh, or approximately 44 microns. In Figure 1, the size of these particles is compared to the size distribution of conventional pulverized coal. As shown, pulverized coal contains a significant fraction of particles greater than 200 mesh, and about 2% exceed 50 mesh size. For a 500 MW power plant, that 2% of the largest coal particles amounts to about 4 tons/hr. The larger particles are important because they produce most of the ash-related impacts.

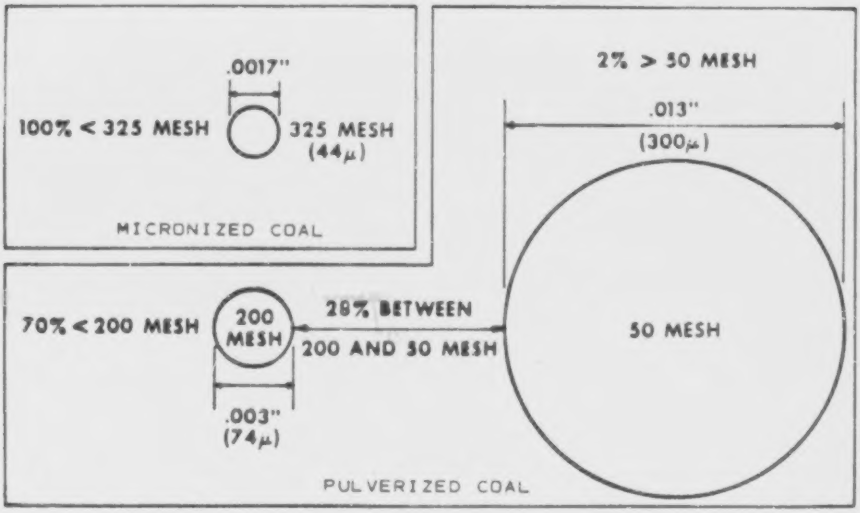

.0017"
100% < 325 MESH
325 MESH
(44μ)
MICRONIZED COAL
2% > 50 MESH
.013"
(300μ)
70% < 200 MESH
200 MESH
28% BETWEEN
200 AND 50 MESH
50 MESH
.003"
(74μ)
PULVERIZED COAL

FIGURE 1 COMPARISON OF MICRONIZED AND CONVENTIONAL PULVERIZED COAL PARTICLE SIZE DISTRIBUTIONS

The effect of particle size is illustrated in Figure 2. Here the flue gas streams in the convection section of a boiler are illustrated. In the upper view, ash-free flue gas, such as that from a gas fired boiler, is shown passing smoothly around a boiler tube. However, if large ash particles are entrained in the flue gas, their inertia causes them to separate from the flue gas stream as it changes direction to travel around the tube. This results in impact deposition on the tube and/or erosion as the particles are swept over the tube surface. This is shown in the middle part of the figure. Another effect not shown here is the tendency for the very large ash particles to drop out of the flue gas stream before it leaves the furnace and to collect on the bottom.

In the third view, we see an illustration of the difference when fly ash particle sizes are smaller, as from micronized coal. This smaller size allows aerodynamic forces to overcome the inertial forces that tend to separate the ash particles from the flue gas flow. The ash remains entrained in the gas and passes around the tubes and is collected in a baghouse or electrostatic precipitator.

A second important effect of finer coal particles is increased intensity of combustion. As noted previously, one of the important differences between coal designed boilers and those designed for oil or gas is the volume of the furnace. Combustion of a solid coal particle is inherently slow, because oxygen is only in contact with the outer surface of the particle. Combustion must proceed inward from this surface. Smaller coal particles have a much greater surface area per unit of mass and, hence, will burn much more quickly than larger ones. This can allow more complete combustion and carbon utilization to take place in the smaller volume and shorter residence time of oil/gas designed boilers.

These factors should make it feasible to burn micronized coal efficiently in the smaller furnaces of oil/gas designed units without the need for major modifications and/or derating. Boilers designed exclusively for gas would probably require cleaner (less ash) and finer micropulverized coal.

For the combustion test performed at the IGT, a Pittsburgh No. 8 coal containing 7.24% ash was ground to three different size distributions, with mass mean particle diameters of 6.6, 18.1, and 41.0 microns. Ten combustion trials were conducted at firing rates and durations ranging from 1.6 to 2.5 x 10^6 BTU/hr and 2 to 75 hours, respectively. Analysis of solid and gas samples collected at various locations along the furnace axis were compared for the different grind distributions, as were differences in total radiant heat flux. Deposition rates were determined using a specially designed convective pass probe, which consisted of two-inch OD gas-cooled tubes located on four-inch centers. Flue gas temperatures at the deposition probe were 2320-2370°F, while tube surface temperature varied from 640 to 1090°F.

Combustion intensity achieved with the finest ground coal was found to be more than twice that for the coarse-ground coal; i.e., 0.9 x 10^5 BTU/hr-ft^3 versus 0.4 x 10^5 BTU/hr-ft^3. Accordingly, flame length was determined to be sensitive to coal size distribution and was reduced by about 60% from the coarsest to finest grind fuel. Somewhat surprisingly, nitrogen oxide emissions did not appear to change with coal particle size distribution. Deposition rates on the convective pass probe were reduced by about 80%, as coal particle size was reduced from the coarsest to the finest distribution.

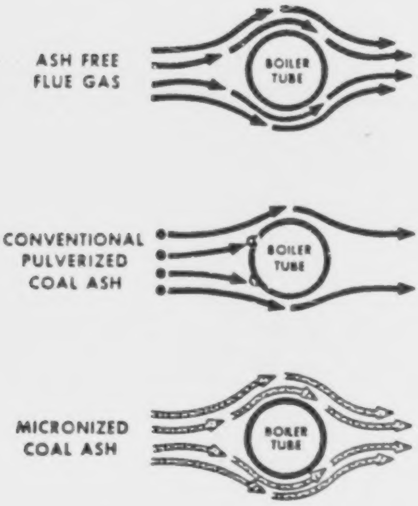

ASH FREE FLUE GAS
BOILER TUBE
CONVENTIONAL PULVERIZED COAL ASH
BOILER TUBE
MICRONIZED COAL ASH
BOILER TUBE

FIGURE 2 COMPARISON OF ASH PARTICLE STREAMLINES

To investigate the technical and economic viability of micronized coal as an alternate fuel, GSU sponsored a similar program with the added objectives of determining if soot blowing could control ash deposition from micronized coal on tightly spaced superheater tube banks. Testing was performed by the Contract Research Division of Babcock and Wilcox Company (B&W) at Alliance, Ohio.

Conventional and micronized grinds of three types of coal (one each from West Virginia, Ohio, and Indiana), representing a range of ash contents and ash fusion temperatures, were evaluated. Ash deposition testing was performed in B&W's Laboratory Ashing Furnace (LAF), a 200,000 BTU/hr test furnace designed to produce fly ash with properties similar to ash from a large utility boiler. The LAF was operated with a furnace exit gas temperature comparable to that of an oil designed unit (2400^{0}F). The ash from each coal burned was collected and analyzed for particle size, carbon content, and elemental ash constituents.

The size of fly ash particles from burning micronized coal was substantially smaller than those from conventional pulverized coal. Ash particles from the micronized coal did not agglomerate appreciably when these coals were burned in the LAF and these particles were small enough to travel with the flue gas around the simulated heat exchanger tubes, while pulverized coal ash particles did not, but instead impacted and deposited on the tubes.

Based on the successful results of the LAF tests, scaled-up tests were conducted in B&W's four million BTU/hr Basic Combustion Test Unit (BCTU) using the same West Virginia Sewell No. 1 coal that was tested in the LAF. A 64-hour, around-the-clock combustion/deposition test was performed using micronized coal. In addition, some limited testing was performed using a finer micronized coal (mass mean diameter of 8.3 microns as compared to 9.4 microns for micronized coal). For comparison, some testing was performed using conventional pulverized coal.

During these tests, the flame from conventional pulverized coal filled the entire BCTU furnace. When burning micronized coal, the flame occupied about 75% of the furnace region. The flame from finely micronized coal occupied about one-half of the furnace length. These results are similar to those obtained at IGT. In addition, as was found in the IGT tests, nitrogen oxide emissions did not appear to change as coal particle size was reduced.

Five parametric combustion tests using conventional pulverized coal were planned to be conducted prior to the full power deposition test with soot-blowing. However, before these could be completed, the deposition test section plugged with ash (see Figure 3). This occurred within seven hours after starting up on pulverized coal. Tube (surface metal) temperatures during this period ranged from 400 to 600^{0}F as compared to 950-1000^{0}F when at full power.

In contrast, when micronized coal was fired, the deposits formed on the tightly spaced tube bank in the BCTU were removed by sootblowing with air (see Figures 4 and 5). During this 64-hour continuous test, tubes were blown at intervals of one to three hours, and base deposits (deposits on the tubes immediately after sootblowing) did not appear to increase with time. These positive results encouraged demonstration testing in a full-size boiler to confirm these test results and address the question of erosion.

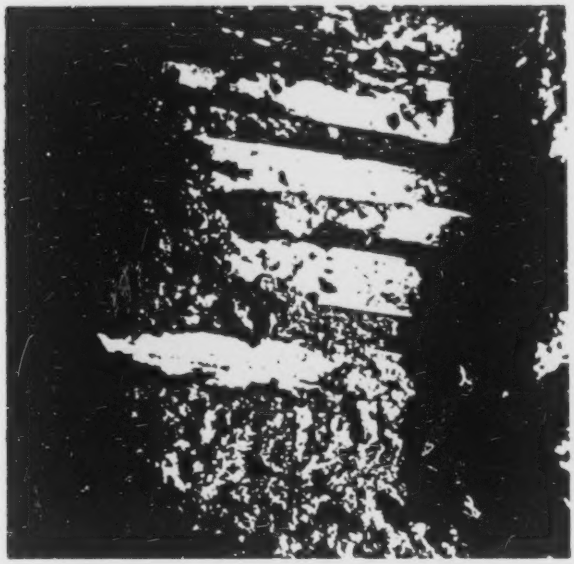


FIGURE 3 PLUGGED TUBE BANK DURING PULVERIZED COAL PARAMETRIC TESTING (WITHOUT SOOTBLOWING)

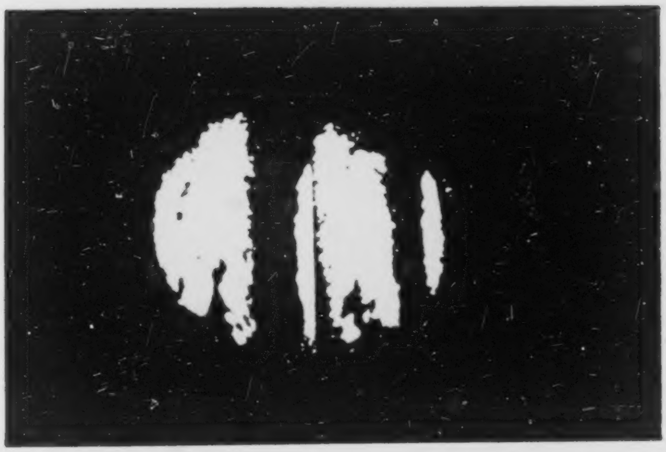


FIGURE 4 Air-cooled tubes prior to soot blowing.

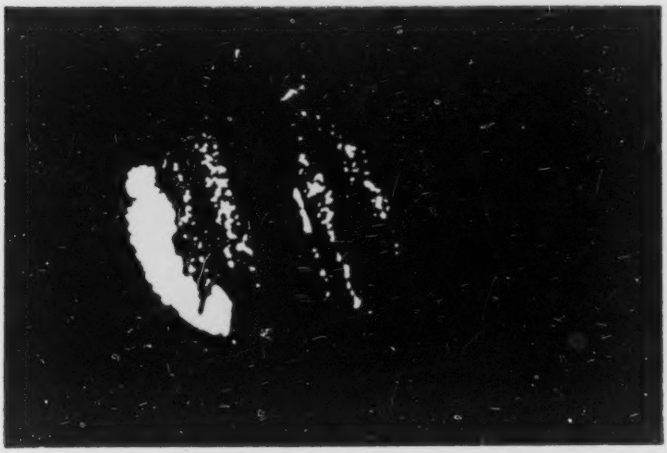


FIGURE 5 Air-cooled tubes immediately after soot blowing.

A step in this direction was taken when MP&L performed a unique test in which micronized coal was fired in four of the twelve burners of a 100-MW unit at their Delta station. Approximately 10,000 tons of coal ground to about 98% less than 44 microns in a 20 ton/hr capacity fluid energy mill were burned. The coal contained about 11.5% ash and accounted for one-third of the heat input to the boiler co-fired with natural gas, which would be roughly equivalent to the use of 4% ash coal (as was used in the GSU-sponsored BCTU tests) in a boiler designed for oil or gas and with future coal capability. Relatively minor accumulation of ash was found on the flat bottom furnace floor and convection section surfaces.

Economic and engineering evaluations have been performed to establish the merits of dry micronized coal conversion for units in the 100 to 150-MW size range and, depending on specific requirements at potential conversion sites, conditions may be obtained which would justify conversion of existing oil/gas fired units to dry micronized coal.

Principal efforts in this area currently are directed at reducing the energy requirements of fluid energy grinding systems capable of micropulverizing coal. Mechanical systems, such as a roller mill, consume less energy in micropulverizing coal; however, transport air requirements are relatively high in present designs and must be reduced to provide good combustion control. This was accomplished in an industrial boiler conversion to micronized coal, by using a semi-direct firing system in which excess air separated in a cyclone unit is recirculated back to the pulverizer.

It is anticipated that as the data base is expanded and experience is accumulated, fuel specifications will be able to be tailored to boiler requirements for cost optimized operation by utilizing coal cleaning, fine grinding and plant derate variables in the most effective manner.

Federal support is needed to accelerate the development and commercialization effort because of the large cost of such a program, which is presented on the estimate of funding requirements that follows. The proposed program is described below.

Proposed Program For Development And Commercialization Of Dry Micronized Coal

The proposed program for the development and accelerated commercialization of clean micronized coal fuels includes:

- Research and Development

  Expand the data base developed in the GSU and IGT testing program to include combustion/deposition testing of a range of coal feedstocks micropulverized to a range of fine grinds and with a range of depths of coal cleaning. This data base would provide the information required to establish fuel specifications with optimum combinations of fine grinding and coal cleaning for various coal feedstocks. This would also provide design information needed to address conversion requirements for a range of site-specific boiler types to have optimum economics and environmental impacts.

- Equipment Development

  Perform the required engineering development and scaleup of micro-pulverizers and coal cleaning systems. This will ensure availability of equipment which will yield minimum plant capacity derating and acceptable emissions.

- Demonstration Testing

  - Modify an oil/gas designed industrial boiler and demonstrate long-term performance with micronized fuel operating with a minimal plant derate in a cost effective environmentally acceptable manner.

  - Scale up such a demonstration test to a 60 to 100 MW and then a 300+ MW oil/gas design utility boiler plant.

  - Another demonstration test is required for burning finer ground micronized coal in boilers designed exclusively for natural gas. The specification for this fuel would provide the appropriate combination of ultra-fine grinding and deeper coal cleaning than required for oil/gas designed boilers.

3. COAL WATER SLURRY COMBUSTION

Recent progress in the development of coal water slurry fuels strongly indicates that improved coal cleaning technology processes, integrated with coal slurry fuel production plants, may be a particularly attractive route for increasing the use of coal as a substitute for gas and oil in a cost effective and environmentally compatible manner.

For most coals, the more finely the raw coal is ground the greater is the release of ash materials and sulfur compounds. Efficient separation and recovery of such coal fines has not been practiced in the past because the cost of such operations and problems related to the safe transport and use of dry powdered coal. However, coal slurry fuels production can have all the benefits of fine coal cleaning while avoiding transport and storage concerns.

Coal slurry fuels are particularly attractive for those facilities where it is impractical to convert to coal, such as oil and gas fired utility and industrial boilers. Here space limitations generally preclude the needed equipment and fuel storage requirements of coal. Use of pulverized coal in facilities designed for oil or gas would require significant capacity derating. However, recent information developed in several experimental programs indicates that finer grinding and cleaning of coal could allow the production of fuels which could be used in oil/gas designed facilities without significant derating. This could result in the eventual displacement of a significant fraction of the approximately 2 million bbl/day of high and low sulfur fuel oil and 2 billion/cu ft/day of natural gas consumed by utility and large industrial boilers.

As a result of extensive development programs supported by DOE and EPRI and privately funded business development efforts, coal water slurry fuel using conventional grind coal is now in the early phases of commercialization. Slurry fuel suppliers have also developed the capability to prepare fuels with finely ground coal of various size consistency, including ultra-fine coal water slurry intended for use in gas turbine and internal combustion engines.

However, large scale demonstration of the production and use of coal water slurry in oil/gas designed boilers is required to establish the relationship between fuel specifications and boiler performance and to confirm fuel system economics. Federal support of such a large scale demonstration could alleviate private industry concerns related to energy project investments and bring about a more rapid and extensive coal water slurry commercialization effort which promises to benefit both national and private economic and environmental interest.

Competitive interests now exist for fuel production, fuel handling equipment, fuel transport, combustion systems, and coal cleaning processes which are required to support a commercial coal water slurry industry. It can be expected that appropriate fuel and equipment refinements will be developed by these interests so as to optimize economic and environmental performance of coal water slurry fuel as a function of user requirements.

Coal Water Slurry Fuel Technology

Coal water slurry (CWS) fuel is a method of processing coal to permit it to be used in oil and gas fired boilers. By grinding coal, cleaning it, and adding water and some chemicals, a fuel in liquid form similar to oil is produced. Such a fuel can preserve the advantages afforded by a liquid fuel. It can be processed offsite at a central preparation facility just as oil is at a refinery. It can be transported to the user just as oil is, and once there, it can be off-loaded, stored, pumped, and burned just as oil is.

"Dense phase" CWS fuel is typically a 70% pulverized coal/29% water mixture plus a 1% chemical additive package to provide desirable flow characteristics and storage stability. This CWS fuel uses coal ground to particle size at or near that of conventional pulverized coal and is much different from "light phase" CWS (50% coal/50% water), which was developed primarily for pipeline transportation of coal. Upon reaching the power plant, light phase CWS requires dewatering and pulverizing prior to firing in a coal designed boiler.

The goal of coal water slurry developers is to produce a substitute for heavy fuel oils which preserves the advantages of liquid fuels for the user while offering the cost advantage of coal. At present, any facility capable of using coal will be able to take advantage of such fuels in those instances where use of dry coal is or may become impractical.

Slurry technology offers an approach whereby environmental benefits of advanced coal cleaning systems can be utilized in a safe and efficient manner. Costs and impacts of transportation and distribution of such fuels may also offer advantages to prospective users.

Because of the ability of slurry developers to prepare a wide range of fuel specifications, it is anticipated that industrial and utility fuel users now dependent on oil and gas will have a cost effective environmentally compatible fuel alternative based on coal. It is also expected that new plant designs may incorporate the ability to utilize such fuels.

Current Status of Development of Conventional Grind CWS Fuel

Considerable effort has been under way by firms in the US and other countries to develop a CWS fuel. Limited commercial production and use of CWS fuel has been achieved in Sweden where the tax on use of oil and excess generation capacity permit acceptance of substantial derating in capacity. Ongoing development and demonstration of CWS fuel in the US and Canada include, among others, programs sponsored by prospective fuel suppliers, equipment suppliers the EPRI, electric utilities, DOE, the New York State Energy Research and Development Agency (NYS-ERDA), industrial firms, and universities. Much of this research and development has concentrated on the development of fuel characteristics related to storage, handling, and combustion in coal capable boilers, but it has not yet fully addressed ash impacts on oil and gas designed boilers. Several producer organizations in the US and Canada are scaling up pilot plant facilities to produce CWS, including such firms as B&W; Combustion Engineering, Inc.; Foster Wheeler Energy Corporation; Atlantic Research Corporation; and Allis-Chalmers, Inc.

EPRI estimates that the combined production capacity of these suppliers by the end of 1984 at about 350,000 tons per year. Government price supports or private development activity could boost this capacity to as much as 1.5 million tons per year by 1986.

The EPRI coal slurry program has accomplished:

o Standardization of slurry characterization tests

o Development of slurry guideline specifications

o Development of technology required to handle and burn CWS fuel

o Performance of an industrial boiler demonstration test at the DuPont facility at Memphis, Tennessee.

EPRI contractors tested properties of CWS fuels whose physical properties varied considerably. Much of this variability can be addressed in the slurry preparation stage. For example, intensive coal cleaning, which can significantly reduce a slurry's ash and pyritic sulfur content, can be incorporated as an integral part of slurry preparation. Because the final product is liquid, the need for drying, the final step in conventional coal cleaning, can be eliminated.

Combustion equipment development has kept pace with fuel development efforts. Three domestic boiler companies--Combustion Engineering, B&W, and Foster Wheeler Energy Corporation, using burners ranging from 15 million to 80 million BTU/hr--have atomizer/burner systems in commercial-scale boiler tests lasting several weeks. Sizes up to 125 million BTU/hr have been tested elsewhere.

A new generation of utility-scale (100 million BTU/hr) burners is under active development. Performance goals include a turndown ratio of 3:1 or better, minimum tip life of 2000 hours, air preheat of less than 300^{0}F, maximum droplet size of 300 microns, and carbon conversion efficiencies greater that 99%.

Larger scale handling and combustion tests, each requiring the preparation of firing of several thousand tons of slurry and lasting for at least one month, have been performed in progressively larger boilers. Early tests in boilers of 8-20 MW capacity highlighted the need for prolonged tests in larger oil-designed utility boilers to resolve performance uncertainties related to the considerably higher ash content of CWS over oil. Results of these tests have been applied in ongoing efforts to optimize burner designs and boiler conditions.

The largest-scale demonstration test conducted in the US to date was sponsored by EPRI in 1983 at an industrial boiler operated by DuPont, in Memphis, Tennessee. Over 35 days, 2500 tons of slurry were fired. Three burners were used, each rated at 15 million BTU/hr and modified with new atomizers and air register changes to produce a high-swirl stable flame.

The DOE programs are complementary to the EPRI activities in investigating handling, storage, and combustion of CWS. Universities have performed experimental research and development studies supplying a broad base of data and an understanding of the time history of atomization and combustion processes with this fuel.

Rapid progress in CWS R&D has brought CWS to the threshold of commercial production and use. The remaining technical issues are considered resolvable, and other significant uncertainties are likely to be resolved, or at least clarified, soon. The US Synthetic Fuels Corporation has solicited and received proposals for production and use of CWS fuel to aid in accelerating its commercialization.

Micronized Coal Water Slurry Fuel

The CWS fuels being developed in activities described thus far contain coal ground to particle sizes at or near that of conventional pulverized coal. Such fuel would be suitable for use in coal designed boilers, but would require major modifications and/or large plant capacity derating if used in oil and gas designed boilers. Successful results in dry micronized coal test programs and combustion tests of CWS fuel containing micronized coal show promise in expanding the applicability of this technology to a broader user base with increasing potential for improved environmental compatibility. These promising test results now require an expanded data base and scaled-up testing and demonstration to confirm technical and economic readiness for commercial application.

Fuel developers have improved the physical characteristics of the fuel to be compatible with available handling and storage equipment and continue to focus attention on overall fuel cost reduction. Prospective users focus on the fuel performance specifications needed to achieve reliable operation with a minimum of plant derate and operational impact. Their primary goal is to develop confidence in the technology through large-scale testing of competing fuel and combustion equipment systems so that it may be used on oil designed equipment with a minimal plant derate in a cost effective and environmentally compatible manner.

Fuel cost and environmental quality concerns dictate the need for developing coal slurry fuel cycles incorporating advanced coal cleaning system technology, which should reduce coal feedstock costs; and cost effective transportation systems, which reduce delivery costs.

Proposed Micronized CWS Development and Commercialization Program

To encourage private interests in their efforts to improve and refine coal water slurry and related equipment, a coal water slurry production and combustion demonstration which would incorporate advanced physical coal cleaning and pulverization equipment capable of producing a range of coal size distributions finer than conventional grind in a fuel production facility is needed. The fuel combustion plant would be of a design representative of the very large numbers of relatively new oil/gas design boilers and be instrumented so as to be able to define plant performance as a function of fuel specifications. The program approach would be based on a scale-up of the current Northeast Coal Utilization Program (NECUP) laboratory scale combustion/deposition test program. Included among the NECUP sponsors are fuel suppliers, equipment manufacturers and fuel users with the common objective of developing various coal water slurry fuels for cost effective application in place of oil or gas.

The proposed program for the development and accelerated commercialization of micronized coal water slurry fuels includes:

- Research and Development

  Expand the data base developed in the NECUP testing program to include combustion/deposition testing of a range of coal feedstocks micropulverized to a range of fine grinds and with a range of depths of coal cleaning. This data base would provide the information required to establish fuel specifications with optimum combination of fine grinding and coal cleaning for various coal feedstocks. This would also provide design information needed to address conversion requirements for a range of site-specific boiler types to have optimum economics and environmental impacts.

- Equipment Development

  Perform the required engineering development and scale-up of burner/atomizer systems, micropulverizers and coal cleaning systems. This will ensure availability of equipment which will yield minimum plant capacity derating and acceptable emissions.

- Demonstration Testing

  - Design, construct and perform demonstration testing in a CWS preparation facility which can, by varying the quality of coal feedstock and the extent of fine grinding and coal cleaning, produce multiple streams of end product to a range of fuel specifications. Also demonstrate highly loaded (>80% coal) CWS handling and transport from the production facility to the point of use, and fuel conditioning at the point of use, in accordance with combustion system requirements.

  - Modify an oil/gas designed industrial boiler and demonstrate long term performance with micronized CWS fuel, operating with a minimal plant derate in a cost effective and environmentally acceptable manner.

  - Scale-up such a demonstration test to 60 to 100 MW and then a 300+ MW oil/gas design utility boiler plant.

- Another demonstration test is required for burning finer micronized coal in boilers designed exclusively for natural gas. The specification for this fuel would provide the appropriate combination of ultra-fine grinding and deeper coal cleaning required for oil/gas designed boilers.

Federal support is needed to accelerate the development and commercialization effort because of the large cost of such a program. This cost is reflected in the following estimate of funding requirements. If effective utilization of existing plants can be implemented in the performance of the program, significant reductions in cost may be realized. Based on the cooperation exhibited by fuel suppliers and users within the NECUP program and their expressed interest in pursuing the commercialization of coal slurry fuels, it is expected that such cooperation will be extended to allow for a cost effective, cooperatively funded demonstration.

MICRONIZED COAL DEVELOPMENT AND COMMERCIALIZATION PROGRAM

ESTIMATE OF FUNDING REQUIREMENTS (in millions)*

	1986	1987	1988	1989	1990	TOTAL
R&D						
Combustion/Deposition Testing (4MM BTU/hr) (Expand Data Base)	.5	1.5	1.5			3.5
EQUIPMENT DEVELOPMENT	.3	2.5	2.5			5.3
Micropulverizers Coal Beneficiation						
DEMONSTRATION TESTING						
CWS Preparation Facility	5	15	25	5.0		50
Industrial Boiler Demonstration Test		.25	1.5	.5		2.25
Small Oil/Gas Utility Boiler Demo Test (60-100MW)			4	15	15	34
Large Oil/Gas Utility Boiler Demo Test (300+MW)				12	40	52
Small Gas Only Utility Boiler Demo Test					4	4
TOTALS	6.0	19.25	34.5	32.5	59	151

*These are estimates of total funding requirements; percentage of DOE and private sector co-funding are unknown at this time.

4. TWO STAGE SLAGGING COMBUSTORS

Two stage slagging combustion is a third advanced coal technology which could enable coal to be used in oil and gas fired boilers. The characteristics of this combustion process allow for highly efficient combustion of coal fuels with sharply lower emission levels. Also, these combustors would allow the use of coal in boilers and furnaces designed for oil and gas.

Description of Technology

The basic concept of two stage slagging combustion involves initial ignition of pulverized coal in a small combustor vessel in a starved air (reducing) environment. The combustion intensity in this primary vessel is very high, resulting in complete gasification of combustion products as well as melting of inert ash components of the fuel. The gaseous products which exit this vessel are essentially a hot fuel/flue gas mixture which would be burned, with additional air, in an existing furnace. The molten ash is collected in the combustor and removed for quench and disposal.

The reducing environment of the primary stage avoids the creation of NO_x during combustion. The secondary combustion is controlled using conventional techniques to maintain low levels of NO_x generation. Testing has proven the ability of this process to hold NO_x levels below 450 ppm (current coal NO_x emission limits) and as low as 150-200 ppm (current oil/gas emission limits).

Refinements of the primary stage combustion process have included injection of various sorbents in an effort to reduce SO_2 formation. Experimentation with various combinations of sorbent type, injection location, combustion duration and slagging condition indicates that SO_2 formation can be reduced substantially. Testing has proven that many non-compliance coals can be burned in slagging combustors within environmental emission limits with no need for costly flue gas desulfurization equipment.

Removal of molten ash from the primary combustor is of value since 1) the amount of ash entering the furnace is reduced by up to 90% and 2) the ash remaining in the flue gases is extremely small particulate (80% <10 microns). These features may permit expanded use of coal on two fronts: retrofit of existing oil fired equipment and improving design of new coal fired equipment. The combustor's ability to reduce the quantity and size of ash particulate in the flue gases allows coal to be used in boilers and furnaces designed for oil with little or no impact on performance. Conventional pulverized coal combustion in such boilers and furnaces would result in furnace slagging and convection section plugging due to ash in the flue gases. Without these combustors, extensive modification to the boiler and derating of unit capacity would be required to avoid these problems. Future application of these combustors to new boilers and furnaces may result in reduced capital cost and physical size of these units, as well as improved emissions performance.

Applicability of Technology

In general, two stage slagging combustion technology is compatible with most combustion equipment, specifically units for the indirect (radiation and convection) heating of fluids and or solids. These include boilers, process heaters, and furnaces. This technology is also applicable to some direct fired process heating equipment where the product would not be contaminated by the small quantities of ash leaving the combustor. These include kilns for lime, soda ash, or similar materials, and furnaces for some glasses and metals.

There are a few technical considerations that limit the applicability of two stage slagging combustion in retrofit or new equipment applications. In most cases feasibility will be determined by economic considerations.

Test results indicate that optimum combustor performance for slag recovery and NO_x generation is difficult to obtain in burner sizes below 50 million BTU/hr. This may be a lower size limit for applicability of these burners.

In retrofit applications, this technology is best suited to equipment designed for oil fuels where little or no derating of capacity would be required. Equipment designed for natural gas, especially boilers with high temperature superheater sections, will be more sensitive to the fine ash particles in the flue gas and would be subject to some level of derating.

To further assess the applicability of this technology, much study has been performed to assess the economic feasibility of retrofit of boilers and furnaces with two stage slagging combustion. These studies have addressed the costs of the combustor installation including all required support and pollution control systems. Additional study is underway as part of the TRW/DOE study program.

These studies have shown that, in most cases, conversion with the two stage slagging combustors would be economically attractive. Payback of conversion costs ranges from 2-3 years, although this has been adversely affected by the recent softness in oil prices. The payback does show typical improvement for larger applications where economics of scale come into play. Economic attractiveness falls off sharply for small (<50 million BTU/hr) size conversions. Also, by comparison, two stage slagging combustor conversion is economically more attractive than conventional pulverized coal conversion.

Recently, studies have been initiated to assess the value of two stage slagging combustors in reducing capital cost and reducing physical size of new boilers and furnaces designed to be fired by these combustors. Boiler manufacturers have undertaken studies to consider the costs of new two stage slagging combustor fired units in comparison to conventional stoker and pulverized coal units. Preliminary information indicates that substantial savings can be realized on large industrial and utility boilers, as well as those designed for low grade fuels.

Current Status of Development

The development of two stage slagging combustion is an outgrowth of DOE sponsored work on Magnetohydrodynamics (MHD). This program required a source of high pressure (6 atm.), high temperature (4500°F) plasma for electric current induction. Coal combustors developed for this application provided high intensity two stage combustion with slag removal and were available for use, with some modification, in atmospheric combustion. To account for the lower pressure and the relatively cooler combustion gases, combustor geometry, air and fuel injection, and slag collection and recovery were slightly changed.

Because of this, it is not surprising to find that the participants in the DOE program for MHD are also the major participants in two stage slagging combustor development. These include TRW (the final selected supplier of MHD combustors for future DOE work), Rockwell International, AVCO, and Coal Tech (established by personnel from GE sponsored MHD work).

Of these four, only TRW and Rockwell have progressed significantly towards commercialization through construction and exhaustive testing of prototype combustor units. AVCO and Coal Tech have continued limited development and simulation, but have no prototype or combustion testing. AVCO recently began limited testing of a combustor prototype under a DOE sponsored program. Due to the early stages of this program, however, the status of TRW and Rockwell represents the current state of the art.

The TRW and Rockwell combustors have taken different approaches to design and operation and therefore can be contrasted on many features. The TRW unit operates at a high combustion intensity requiring a relatively small combustor vessel. A 100 million BTU/hr unit, for example, is about 4 feet in diameter and 11 feet in length. The high intensity requires high pressure combustion air and water cooling of the bare metal combustor internals. While water cooling would prevent corrosion of metal parts by combustion products, it may, in some retrofit installations, lead to complicated integration requirements for heat recovery.

The Rockwell unit is larger with less than half the combustion intensity. This lower heat release allows for use of refractory lining for some metal combustor internals. This reduces integration problems, but may complicate operation and maintenance of the combustion unit. Refractory has a poor history for life and reliability when operating in slagging environments and requires long warm up and cool down cycles.

TRW has performed extensive short term (2-3 hours) testing on three prototype units ranging in size from 1 to 50 million BTU/hr. Most testing was performed on a 10 million BTU/hr unit. The TRW program focused first on slag capture and NO_x control, features considered to be essential for retrofit of oil and gas boilers. After optimization of these parameters, obtaining removal of 90% of coal ash as slag and producing as little as 250 ppm of NO_x, TRW began testing SO_2 control methods. Current testing is continuing with emphasis on variation of operating parameters to obtain simultaneous performance of 90% slag capture, 250 ppm NO_x and removal of 50-80% of fuel sulfur.

TRW has also initiated a program to provide long term (4,000 hours) combustor performance testing through the retrofit of a small industrial boiler to fire coal with a 50 million BTU/hr unit. This long term data is essential to commercial acceptance of the combustor for retrofit or new installations. TRW has assembled a Users Group of potential combustor users to partially fund this demonstration. This ten member group also serves to advise TRW on combustor design and performance preferences. Actual retrofit is underway with startup of this demonstration unit expected in mid-1985. TRW is also performing an extensive program to explore combustor operations to enhance sulfur capture and operate on a wide variety of pulverized and coal water slurry fuels. This program, funded by DOE, TRW and others, includes the installation of a boiler simulator to obtain data regarding the interaction of the combustor with boiler internals during retrofit operation.

Rockwell International has performed fewer short term tests than TRW and has, in general, focused on low NO_x and SO_2 emissions with little emphasis on slag collection or removal. SO_2 and NO_x control and the slower combustion required for this control have caused, to some extent, the larger size of the Rockwell unit. Most testing has been performed on a 7.5 million BTU/hr combustor unit which is partially refractory lined, but requires some water cooling. Testing reported to date has obtained up to 90% sulfur removal and 150-220 ppm NO_x with no slag removal. Recent testing has begun to address the slag removal issue with the installation of a slag capture tube bank. This method of slag removal has possible operation problems, such as clogging at low load. Additional testing is planned to prove this concept.

Rockwell is planning a long term demonstration of first a single and ultimately multiple combustors in the 100 million BTU/hr size range. Rockwell has also assembled a sponsor group of 4-5 utilities to fund this program, and advise and comment on combustor design and testing. The planned schedule for this demonstration is late 1985-1986.

A table summarizing TRW and Rockwell design, performance and testing is attached.

Development Goals

Both TRW and Rockwell development programs are proceeding toward commercialization. The demonstration programs planned represent only the first of several commercial demonstrations required prior to industry acceptance of this combustion technique. Development of these technologies will require substantial R&D expenditures.

The future of this technology will be greatly affected by the performance of these first demonstration units. If operating problems are found, or unit performance is below prediction, developers and interested users may be discouraged and reduce funding support. The energy markets and continued interest in coal conversion are also important components in the development.

Technically, several issues must be dealt with--optimization of simultaneous slag capture, sulfur removal and low NO_x generation. Also, testing is needed to verify the ability of these combustors to perform on a variety of coals (eastern, western, etc.) and coal slurries. Finally, scaling of the combustor units from the proven 50-100 million BTU/hr sizes to the likely maximum size of 250-300 million BTU/hr must be accomplished.

The combustors as currently developed and operated are, in comparison to conventional burners, complex. Accurate metering of multiple combustion air and fuel feed points is required to maintain proper combustion, emission and slagging performance. These complexities would be expanded in a multiple burner boiler where up to 30 combustors would operate simultaneously.

COMBUSTION PERFORMANCE COMPARISON

	SLAG REMOVAL PERCENT	FLY ASH SIZE	NO_X (PPM)	SO_X (PERCENT)	REDUCTION (Ca/S)	CARBON BURNOUT PERCENT	TURN DOWN (RATIO)	START UP (MIN.)
TRW	80-90	85% <10 u*	250-450	40-60	(1.5-2.5)	99.5	3.1	20
ROCKWELL	50-80	95% <10 u**	50-150	60-90	(0.9-2.0)	85-95	4.1	180

COMBUSTION DESIGN COMPARISON

	SIZE DxL (FT)***	WEIGHT*** (TONS)	INSULATION (TYPE)	COOLING (MEDIA)	% HEAT TO COOLING WATER	FAN PRESSURE (in H_2O)	AIR PERHEAT (^oF)	COAL FEED TYPE
TRW	5x11	6	SELF GENERATED SLAG	WATER	8-10	30	400-650	INDIRECT
ROCKWELL	6x24	25	REFRACTORY	NONE/WATER	8	30	650	DIRECT

COMBUSTION TESTING/DEMO COMPARISON

	COMBUSTORS TESTED MM BTU/HR	COMBUSTORS TESTED (HRS)	DEMONSTRATION INDUSTRIAL	DEMONSTRATION UTILITY (MM BTU/HR)	STATUS
TRW	1, 10, 50 (35-200 @ 6 atm)	800	50	--	IN PROGRESS
ROCKWELL	17, 25 (70 @ 6 atm)	200	—	100 (1-3 UNITS)	PLANNING

*PRELIMINARY TEST DATA
**EXPECTED (NOT MEASURED)
***FOR A 100 MM BTU/HR UNIT

Testing has shown the combustion to be relatively insensitive to variations in fuel moisture, heating value and ash content. Optimum operation, however, for minimization of NO_x and SO_2 emissions while maximizing slag capture, may require operation within a small band of conditions. The ability of two stage slagging combustors to operate on a regular basis and maintain near optimum operation must be demonstrated.

As commercial utilization becomes a reality, development programs must be undertaken to better define hardware integration issues. These include large industrial and utility scale retrofit integration of combustor shell heat recovery and slag collection and quench, mechanical interface between combustor and boiler or furnace, and integration and simplification of combustor system controls.

Proposed Future Development Program

The development and demonstration programs underway or planned will serve to prove the combustor concept. Both the TRW demonstration program and the planned Rockwell program will test the combustor in boilers originally capable of coal firing. Also, these programs will test combustor units on the lower end of the size range and for boiler service only. Prior to wide spread commercial acceptance of this technology for retrofit of oil and gas fired industrial and utility boilers and more complex applications, additional development and demonstration will be required.

These development and demonstration programs would provide for the improvement of combustor performance to meet the operating requirements of larger, utility scale coal firing of oil and gas designed boilers; operation with exotic or waste fuels; and non-boiler applications.

Areas which will require development and demonstration programs are described briefly below. The following table identifies funding required for these programs over the next decade.

SO_2 Control Development/Improvement -- SO_2 control development programs would explore the SO_2 removal process to improve the current 60% removal levels to a 90% level required for larger scale and utility applications.

Combustion Scaling -- Combustor scaling from its current 50-100 million BTU/hr size to a 250 million BTU/hr size will be required for large utility units. The internal flow and combustion patterns will vary as the unit diameter increases.

Utility Scale Demonstration -- A demonstration program will be required to prove the combustor in large scale units and multiple burner applications such as utility boilers. These boilers would represent the most stringent requirements for NO_x and SO_2 control.

Direct Fired Gas Turbine Development/Demonstration -- Much interest has been expressed on the potential application of slagging combustors to direct fired gas turbines. This would require improvement of slagging performance and demonstration to prove the concept.

Alternate Fuels -- Alternate and waste fuels such as petroleum coke, lignite, oil rig wastes, pump black liquor and coal wash plant tailings would allow use of the combustor in a wider variety of applications. Each fuel, however, has sharply different properties requiring development programs to optimize combustion.

Complex Applications -- There are several advanced applications of the slagging combustor technology. These applications involve processes or combustion systems which must be closely explored after the technology is proven and accepted on a wide scale. Such applications are limitless but include, as a minimum, combustor fired locomotive engines and combustor based steel reduction furnaces.

SLAGGING COMBUSTOR DEVELOPMENT/DEMONSTRATION ACTIVITIES FOR DEPARTMENT OF ENERGY SUPPORT

DEVELOPMENT COSTS (MILLIONS $)

ACTIVITY	1986	1987	1988	1989	1990	TOTAL	Additional Private Sec. Co-funding 1985-1994	TOTAL
Industrial Demonstration	Underway	--Commercial Support--					6	6
SO_x Control Development/ Improvement	0.5	1		1		2.5	2	4.5
Coal Water Slurry Combustion	0.5	1				1.5	1	2.5
Combustor Scaling		2	1			3.0	1	4
Utility Scale Demonstration		3	9	4	2	18.0	4.0	22.0
Direct Fired Gas Turbine (Development/ Demonstration)		2	2	3	5	12.0	4	16.0
Alternate Fuels Petroleum Coke Lignite Oil Rig Wastes Black Liquor Wash Plant Tailings		1	2	3	3	9	1.5	10.5
Complex Applications Locomotive Engines Steel Reduction Furnaces				1	1	2	2	4
TOTAL	1	10	14	11	11	47.0	13	70

(TOTAL 1986-1990 = 70 MILLION)

5. LIMESTONE INJECTION MULTISTAGE BURNER (LIMB)

LIMB combines sorbent injection for SO_x control with low-NO_x burners for NO_x control. Low-NO_x burners of various designs have been developed by both EPA and private industry and are capable of retrofit applications. The SO_x control by sorbent injection is an emerging technology which has been developed by the EPA. The reaction of SO_x with sorbents (i.e., limestone and other alkaline solids) is well known under proper conditions (e.g., wet FGD). LIMB is based on injection of a sorbent directly into the furnace and its subsequent reaction with gas-phase SO_2 to form a dry calcium sulfate. The amount of SO_2 that can be captured is dependent on the type and amount of sorbent, its mixing with combustion gases and fly ash in the furnace, and its thermal history. The relative simplicity of the technology lends itself to a relatively low cost retrofit on a wide variety of systems. The technology has the potential to reduce both SO_x and NO_x by 50-60% for retrofit applications and by 70%-90% for new sources at a cost of at least $100/kw less than existing technologies such as FGD.

Applicability of the Technology

The technology is potentially applicable to pulverized coal-fired industrial and utility boilers. The technology may be considered either for retrofit of the existing population or on new systems for compliance with New Source Performance standards.

Sulfur oxides (SO_x) and nitrogen oxides (NO_x) are two major pollutants resulting from the combustion of fuels. Coal fired utility boilers account for about 70% of the SO_x and 20-25% of the NO_x emissions in the US. For the 180,000 MW of boiler capacity east of the Mississippi River, this amounts to approximately 16 million tons of SO_2 and 4-5 million tons of NO_x per year. Only about 10% of these boilers are subject to NSPS controls for SO_x and NO_x. Therefore, to accomplish any significant reduction in SO_x and NO_x requires a retrofit of existing boilers which may have a remaining useful life from 5 to 30 years or more.

Within this population of coal fired utility boilers there are two major design types which must be addressed: 1) wall-fired boilers, which are manufactured by B&W, Foster Wheeler and Riley Stoker; and 2) tangentially-fired boilers, which are manufactured by Combustion Engineering. Each type is about 45% of the existing population, with up to 10% in other designs. Due to significant differences in the firing system, any technology which involves changes to the combustion must be developed for each major type.

The biggest single advantage of LIMB for existing boilers is its potential cost advantage over existing technologies. For a typical 500 MW plant the capital cost savings (at $100/kw less than FGD would be $50 million. In addition, recent cost modeling shows that LIMB can offer operating savings of between $270 to $1000 per ton of SO_2 removed depending on a number of operational factors. This represents operating costs that are 27% to 45% less than those for FGD.

For existing boilers, application may be limited by the thermal profile within the boiler and by access for satisfactory injection and mixing of the sorbent. In cases where these factors are favorable, convective pass tube spacing and particulate control systems must be capable of handling the increased solids loading. however, the ultimate retrofit applicability will depend most strongly on the mandated strategy for control of acid rain percursors.

There is an even stronger potential for new boiler systems. Dependent on the assumed capacity growth, the use of LIMB instead of FGD for SO_x control on low sulfur (up to 1.5%) coal fired NSPS boilers might produce capital cost savings up to $10 billion. The operating cost savings estimate range from $800 to $1900 per ton of SO_2 removed, or 40 to 60% less than FGD.

New boiler systems can be designed from the ground up to accommodate the LIMB system using relatively conventional boiler technology. The temperature profile, injection points, convective pass spacing and particulate control can be tailored to optimize the process. This application appears particularly favorable for low to moderate sulfur coals (<1.5%) where NSPS requires 70% control of SO_2.

Current Status

The majority of the R&D in the US has been provided by EPA under funding both in-house and at its contractors. There are modest efforts at various government and private sector laboratories. The EPA's LIMB program has been structured to give the best probability of achieving the stated goals of moderate SO_x and NO_x control (50-60%) at low cost with applicability to the major portion of the existing boiler population. The major research objective is to provide the basis for widespread private sector commercialization based on successful demonstration of the technology on both a wall-fired and a tangentially-fired boiler. To achieve this objective the research program has been divided among the following four areas: generic research and development, prototype testing, full-scale demonstration and technology generalization. These four areas have been used to discuss the progress to date as a result of all public and private R&D. A brief description of the current status of each area is presented below.

Generic Research and Development. Much of the LIMB research in the US has been based on the fact that a complete understanding of the process is necessary to given the maximum probability of successful commercialization by the private sector. R&D of this type is relatively independent of the hardware specific constraints of practical boilers and provides information essential for application of LIMB to all boiler designs.

The generic research and development has provided excellent insights on the effects of critical process parameters on SO_2 capture. The research has examined the effect process parameters have on sorbent activation and subsequent sulfur capture, as a function of combustion system conditions. Recent EPA test results from LIMB experimental boilers indicate that limestone injection alone will only achieve 40% sulfur removal efficiency, lower than originally estimated. However, other tests have indicated that the LIMB SO_2 removal goals can be met with at least two alternate approaches: high surface area sorbents (calcitic and dolomitic hydrated limes) or sorbents with mineral promoters (small amounts of inexpensive innocuous materials to enhance sorbent reactivity). The use of a high surface area sorbent or sorbents with promoters will increase LIMB costs by about 10%, the estimated capital cost for LIMB would still be 20% to 30% that of a wet scrubber. Additional R&D necessary to address these high activity sorbents is discussed in the next section. The R&D has also provided an understanding of fly ash/sorbent mixture characteristics as related to slagging, fouling and particulate capture.

Prototype Testing. The results of the pilot scale generic research must be scaled up to large size boiler systems. As an intermediate step prior to a demonstration, prototype testing is being carried out in large experimental systems. Within the research area, alternate sorbent injection designs and optimum injector locations are being evaluated, and scale up criteria are being developed. These tests have shown that the burner design is not the dominant factor in achievable SO_2 capture and that sorbent selection and injection conditions are critical.

Demonstrations. Initial LIMB development has focused on the wall-fired boiler because research data and large scale experimental facilities were available. A demonstration program for a representative wall-fired utility boiler was initiated in FY 1984. EPA awarded a contract for such a wall-fired demonstration in September 1984 to the Babcock and Wilcox Company (B&W). A 105 MW wall-fired boiler will be modified by B&W for the LIMB technology at the Edgewater Station of the Ohio Edison Company. The final site specific design for the installation will be completed in February 1986. Year long term testing will begin in July 1987, and a report evaluating the LIMB performance will be completed in March 1989. EPRI has initiated an effort to perform R&D testing on a small boiler (20-100 MW) and to ultimately retrofit a 400 MW plant; however, no arrangements have been announced. The Europeans are involved in numerous boiler injection tests (most of which are low rank coals) which are atypical of US fuels. The Weiher III testing in Germany using a black coal has EPA participation in the measurement phase. Several tests in small boilers (<60 MW) have been performed in the US with encouraging results.

Technology Generalization. Activity in this area has been limited to the exchange of information with other researchers and potential users of LIMB. This exchange included a joint EPA/EPRI Conference on LIMB which was held in November 1984.

DEVELOPMENT GOALS

The technology is currently being aggressively carried through the development stage by the US EPA LIMB program. In that program the research needs are structured in the four categories previously described. The research needs described are those which were identified during a recent OEET/ORD review of the LIMB program and during the recent EPA/EPRI symposium.

Generic Research and Development. Recent research results have identified increased sorbent surface area as a key factor in obtaining high sulfur capture. It has been shown that high surface area can be generated external to the combustion process and/or in situ. These high surface area materials have shown the potential for sulfur capture in excess of 70%. The planned R&D addresses methods for obtaining highly reactive sorbents, for optimizing reaction conditions to achieve maximum capture, and for minimizing sorbent costs.

Another key factor is the interaction of sorbents with mineral matter, which can either enhance or degrade the sorbent reactivity. The most promising results indicate that it may be possible to add small amounts of relatively inexpensive, innocuous promoters (mineral compounds) which will enhance the sorbent activity. Sulfur captures approaching those of high surface area sorbents have been achieved with promoted limestone in limited bench scale experiments. It also appears that promoters can significantly improve the performance of high surface area sorbents. A significant effort is necessary to understand the enhancement mechanisms and to provide the basis for use in practical systems. It should be noted that a similar understanding is necessary for other sorbent/mineral matter interactions which can inhibit sulfur capture and which affect slagging, fouling and collection characteristics of the particulate.

Process analysis has indicated substantial benefits may be derived from recycle of unreacted sorbent and promoters. In addition, utilization of the spent sorbent and fly ash has significant potential economic benefits. Pilot scale R&D is necessary to evaluate the engineering feasibility of these process options.

Specialized measurements, which are required for LIMB R&D and demonstrations, are also provided in this area. These on-going activities include routine and developmental analyses for sorbent characteristics and LIMB particulate form.

Prototype Testing. Prototype work is essential for scale up of the performance improved sorbents and for tangentially fired boiler systems. This testing will address criteria for injection of high activity sorbents into a thermal environment representative of all US boilers. The testing on wall-fired prototypes will build directly on previous experience with a wide variety of burner designs. The optimum injection locations must be selected for each class of sorbents based on smaller scale R&D. Injector designs must be evaluated and scale-up criteria developed. Prototype testing for tangentially-fired systems will be initiated to examine similar design features in the presence of a vortex flow field. Both cold flow modeling and large scale combustion tests are planned. Finally, a cooperative program of testing on a small boiler (20-40 MW) will be initiated to examine both sulfur capture and operability/reliability impacts. Flexible operation, including types of fuel and sorbents, will provide an attractive R&D complement to full-scale boiler demonstrations. It may also allow an assessment of applicability of LIMB to industrial boilers.

Demonstrations. As was previously mentioned, the utility industry will not adopt the LIMB technology until it has been demonstrated in full-scale facilities. There are two major types of boilers which represent about 90% of the boiler population in this country. These are wall-fired boilers and tangentially-fired boilers. Because of the substantial difference between the firing systems, technology developed for wall-fired systems is not directly applicable to tangentially-fired systems.

The contract for the wall-fired demonstration has been awarded to the Babcock & Wilcox Company, who will install LIMB on a 105 MW single wall-fired unit. The final site specific design for the installation will be completed in February 1986. Long term testing will begin July 1987 and a report documenting the performance evaluation will be completed in March 1989. The funding to complete the effort is provided in the FY85 budget and no outyear contingency funds are identified. Any supporting work will be provided by the generic R&D program.

Technology Generalization. For ultimate wide spread use of the LIMB technology the R&D results must be integrated with the full scale boiler demonstration results to provide guidance for commercialization by the private sector. The program includes both process analysis to evaluate applicability and economics for specific systems and process modeling to provide a methodology useful for site-specific designs. In FY85 and FY86, the process analysis has emphasized LIMB system options for application to different boiler classes in the population and for minimizing the cost per unit SO_2 removal. The process modeling will provide component models for thermal history, sorbent activation and reaction, injection, and mixing. Funding is provided in FY87 to FY89 for integration of these models into an overall design tool.

PROPOSED FUTURE DEMONSTRATION

A tangentially-fired demo is not provided in the current EPA budget scenario. The generic R&D results provide the basis for application of LIMB to tangentially-fired boilers. However, only limited system specific development has been done. One key factor in obtaining acceptable SO_x capture is injection and mixing the sorbent at the proper combustion conditions. The injection and mixing of sorbents is complicated by the vortex action produced in the combustion gases by tangential firing. To date only limited small pilot scale development has been performed with representative combustion conditions. It is estimated that a full-scale demonstration will require $10-15 million government funding, assuming 50/50 co-funding with the private sector. Due to the EPA lead role in development of the technology, the Board strongly urges a cooperative DOE/EPA program in this area.

TABLE 1

TIMELINE FOR LIMB PROGRAM

PROGRAM RESOURCES BY (IN MILLIONS)

PPA	PROJECT AREA	FY86	FY87	FY88	FY89	FY90	FY91	FY92	FY93
01 GENERIC R&D	Characterization, Generalization and use of High Surface Area Sorbents	$ 2235	1500	1008	100				
			x $3628		x $3622	F			
	Interaction of Sorvent & Mineral Matter - Effects on SO_2 Capture & Particulate Characteristics	969	1261	585	100				
			x $3620		x $3727	F			
	Sorbent Recycle/Utilization Process Options for LIMB		300	0	400	200			
				o	x $4157	F			
	Generic R&D Support for Demonstrations				350	450	350	350	
					o				F
	Analytical Support	209	325	100	200	100	50	50	
									F
	PPA SUBTOTAL	$3415	$3386	$1693	$1150	$ 750	$ 400	$ 400	
03 PROTOTYPE	Injection and Mixing of High Activity Sorbents for Wall-Fired Systems	901	950	750					
			x $3626			x $4084			
	Injection and Mixing of High Activity Sorbents for Tangentially-Fired Systems	0	1252	0					
			o		x $3625				
	Cooperative Prototype Small Boiler Testing	0	1506	0	0	0			
				o		x $4158			
	PPA SUBTOTAL	$ 591	$3708	$ 750	$ 0	$ 0	$ 0	$ 0	$ 0

TABLE 1
TIMELINE FOR LIMB PROGRAM

PROGRAM RESOURCES BY FISCAL YEAR (IN MILLIONS)

PPA	PROJECT AREA	FY86	FY87	FY88	FY89	FY90	FY91	FY92	FY93
06 COMMERCIALIZATION	Synthesis and Generalization of Critical LIMB Factors	$1205	1988	437	200	300	400	200	100
		- - - -	- - - -X- $3631	- - I - - -	-X- $3632	- - - - - -	I- - - -	I- - - -	- -F
	Cofunded Demonstration of LIMB Technology on a Wall-Fired Boiler	1700	4363						
			o X $3633	X $3634			X $3728		
	LIMB Technology Transfer and Congressional Reporting	84	75	75	50	50	50	50	50
		- - - -	-S- - -X- $4129	- - - I	-S- - -I-	S - - I-	-S- - I	- - - - -I-	- - - - F
	Cofunded Demonstration of LIMB Technology on a Tangentially-Fired Boiler	0	0	0	$9000	$2000			
						o I			X $4130
	PPA SUBTOTAL	$2989	$6426	$ 512	$9250	$2350	$ 450	$ 250	$ 150
	R&D SUBTOTAL	7514	13120	2955	10400	3100	850	650	150
	Overhead @ 8% of Total FY 87-90	1217	1362	245	896	270	65	50	12
	FUNDING TOTAL	$8522	$14882	$3200	$11300	$3370	$ 915	$ 700	$ 162
	FTE's	27.4	33.8	27.5	27.5	22.5	20	15	12.5

KEY:

o	Start	X Existing PPA Deliverable - # Code - See Attached
- - -	Continuation	I Interim Report or Decision Point
____	New Work	F Final Report - Will be Future Deliverable

(Total FY 86-90 = $41 million)

TABLE 2

TIME LINE FOR OPTIONAL PROGRAM - NSPS LIMB

PROGRAM RESOURCES BY FISCAL YEAR (IN THOUSANDS)

PPA	PROJECT AREA	FY87	FY88	FY89	FY90	FY91	‘FY92	FY93	FY94
07 M S	Pilot Scale Evaluation of Optimum LIMB Process Design	$ 400	800	0	0				
			o-------X----------F						
P S	Prototype Scale Confirmation of Optimum Design		200	1500	500				
				o------------------F					
L I M B	Process Analysis & Support	100	100	100	400				
			o------------I--------------F						
S	Cooperative Evaluation of NSPS LIMB on a Full-Scale Boiler					2000			
							o----------I----------------F		
	TOTAL PROJECT	$ 500	1100	1600	900	2000			
	OVERHEAD	40	88	108	72	160			
	TOTAL R&D	540	1188	1708	972	2160			
	FTE's	2	3	5	4	3	2	2	2

6. LOW NO_x SYSTEMS/DUAL FUEL OVERFIRING

Advanced combustion modification technology can be utilized to achieve NO_x reductions ranging from 50 to 85%. One such technology, known as dual fuel overfiring or reburning, is capable of being used on new or retrofit applications. It can also be applied in combination with other low NO_x techniques, such as low-NO_x burners, to optimize the NO_x reduction. For example, the two stage slagging combustor (described in another section) could potentially utilize reburning to minimize NO_x emissions. Reburning also has potential for combined sorbent injection to achieve simultaneous NO_x and SO_x reduction.

Description of Technology

The basic concept of dual fuel overfiring, or reburning, involves the use of a second combustion zone downstream of the primary flame zone. This "reburning zone" is usually operated fuel rich in order to create a reducing zone in which NO_x formed in the primary zone is reduced to N_2 and H_2O. Air to complete burnout is injected downstream of the reburning zone. The fuel used for reburning can be the same as that used in the primary zone, or can be different. Bench-scale tests have shown that it is desirable to use a fuel with a low fuel nitrogen content in the reburning zone in order to maximize its effectiveness.

It is also desirable to operate the primary combustion zone at as low an excess air level as is practical. This minimizes the amount of fuel needed to reach a stoichiometric ratio of about 0.9 in the reburning zone.

It has been found that air staging can achieve NO_x reductions of the same magnitude as reburning. However, the large reducing zone which is created to achieve the same NO_x reduction levels can create a severe tubewall corrosion problem. With reburning the reducing zone can be very small and steps can be taken to minimize or eliminate the corrosion problem.

Applicability of Technology

Reburning can be used on a wide variety of commercial combustors such as boilers, kilns, and process heaters. However, its application and effectiveness will vary depending on combustion design and fuel fired.

Application to any new design of combustor should be straightforward. However, retrofit application will depend on factors such as heat release rate and fuel availability.

If applied to an existing coal-fired boiler, coal could only be used as the reburning fuel if there is sufficient time for complete carbon burnout. In a tightly designed boiler it may be necessary to use natural gas as the reburning fuel.

It should be relatively easy to apply reburning to a precalciner cement kiln. Since the kiln cannot be operated fuel rich due to the effect on clinker quality, gases exiting the kiln could be passed through a reburning zone in the precalciner section of the kiln.

Based on bench-scale tests reburning should also be applicable to other combustor types, such as refinery process heaters. NO_x reduction levels approaching 85% were achieved on a system using natural gas as both the primary and reburning fuel.

Current Status of Development

Dual fuel overfiring is also known as fuel staging, in-furnace NO_x reduction, and MACT (Mitsubishi Advanced Combustion Technology). The process was originally investigated in the late 1960s and early 1970s by J.O.L. Wendt and C.V. Sterling, who coined the term "reburning". Further work was performed by A. Myerson. Each of these investigators performed laboratory-scale research which was reported at meetings of The Combustion Institute in 1973 and 1975. Until 1981 little was heard about the technology. At the US/Japan Information Exchange, which was held in Tokyo in May 1981, several Japanese companies reported on results of bench- and pilot-scale tests using reburning to achieve a 50% NO_x reduction.

Prior to the US/Japan Information Exchange, DOE had sponsored bench-scale tests, performed by Acurex Corporation, to further investigate reburning. Following the May 1981 meeting, EPA decided to sponsor further research to scale-up the technology and evaluate its effectiveness on US designed boilers. EPA sponsored laboratory-, bench-, and pilot-scale tests on 7,000 BTU/hr, 60,000 BTU/hr, and 10,000,000 BTU/hr test facilities, respectively, which were performed by Energy and Environmental Research (EER) Corporation. In addition, tests were performed in-house by EPA on a 3,000,000 BTU/hr package boiler simulator and a 2,500,000 BTU/hr Scotch type boiler to evaluate application of reburning on package boilers. The Gas Research Institute is currently sponsoring additional tests at EER to obtain data for reburning with natural gas. Tests have also been sponsored by EPRI on a 100,000,000 BTU/hr coal-fired test facility operated by Riley Stoker. In Japan, reburning has been applied to several full-scale utility boilers.

In general, tests performed to date have shown that the way reburning is applied is critical to its success. If properly applied it is capable of achieving NO_x reductions of 50% to 85%, depending on the type of combustor, fuels fired, and NO_x levels in the primary combustion zone.

DEVELOPMENT GOALS

It is desirable to apply the reburning technology which has been developed to US-designed boilers, kilns, process heaters, etc. This technology can be used on a new or retrofit basis and is an order of magnitude less expensive than the alternative of flue gas treatment.

Further investigation is necessary to evaluate the potential of sorbent injection in the reburning zone for simultaneous NO_x/SO_x control. However, bench-scale tests performed by EER have shown that this option has good potential. The temperature and residence time in the reburning zone appear to be ideal for sulfur capture by a sorbent material.

As commercial utilization becomes a reality, development programs must be undertaken to better define potential operating problems such as carbon burnout, corrosion, and combustion efficiency. Evaluation of reburning on a wide variety of combustors will be desirable.

PROPOSED FUTURE DEVELOPMENT PROGRAM

The bench- and pilot-scale programs that are currently underway or planned will serve to prove the reburning concept. However, prior to widespread commercial acceptance of this technology for new or retrofit application, additional development and demonstration will be required.

These development and demonstration programs would provide for improved NO_x reduction and for further evaluation of sorbent injection for SO_x capture. It is recommended that DOE support such demonstration programs since they will lead to increased coal usage in an environmentally acceptable manner. EPA should be directly involved to ensure technology transfer and in order to maximize the NO_xSO_x reduction potential.

As reburning is applied to specific types of combustors it would be desirable to involve relevant organizations both technically and financially, where possible (e.g., EPRI for utility boilers, GRI for gas-fired combustors).

Demonstrations should be planned for industrial boilers, utility boilers, cement kilns, refinery process heaters, and other combustors which emit relatively high levels of NO_x. Its application should also be evaluated on two stage slagging combustors. Reburning should be applicable to practically all combustor types.

LOW NO$_x$ SYSTEMS/DUAL FUEL OVERFIRING
ESTIMATE OF FUNDING REQUIREMENTS (MILLIONS)*

	FY86	FY87	FY88	FY89	FY90	TOTAL
Application/Demonstration of Reburning to Industrial Boilers	0.50	1.0	1.5	1.0		4
Application/Demonstration of Reburning to Utility Boilers		2.0	5.0	5.0	5.0	17
Application/Demonstration of Reburning Combined with Sorbent Injection to Utility Boilers			5.0	10.0	10.0	25
Application/Demonstration of Reburning to Cement Kilns				3.0	5.0	8
Application/Demonstration of Reburning to Two Stage Slagging Combustors					3.0	3
TOTALS	0.50	3.0	11.5	19.0	23.0	57

*These are estimated of total funding requirements; percentage of DOE, EPA and private sector co-funding all unknown at this time.

C. COMBUSTION II.
FLUIDIZED BED COMBUSTION

by: Kurt Yeager

I. DEFINITION OF SUBJECT

This section will review the status and outlook for both Atmospheric Fluidized Bed Combustion (AFBC) and Pressurized Fluidized Bed Combustion (PFBC). Fluidized bed combustion (FBC) is an evolutionary improvement in coal-fired boiler design that has the potential of providing significant advantages over conventional pulverized coal boilers.

Interest in FBC technology stems from three primary characteristics: the ability to control SO_2 and NO_x emissions without concern for ash properties or quantity, and the potential to reduce both capital and operating costs when compared with current technology. In the case of PFBC these advantages are further augmented by the opportunity for higher thermal efficiency and increased modular construction.

II. STATE OF THE ART

1. Atmospheric Fluidized Bed Combustion (AFBC)

The fluidized-bed boiler that operates at near-atmospheric pressure on the fire side is a relatively simple boiler, no different in purpose than the pulverized-coal and stoker boilers more generally used today. Fluidized-bed boilers can generate steam at the pressure and temperature needed by modern steam turbines through conventional heat transfer; only the firing system is different.

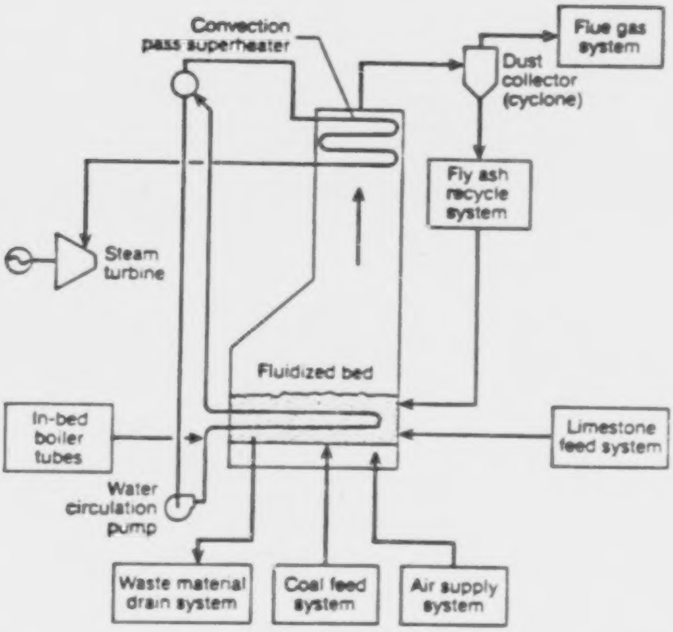
In fluidized-bed combustion, the fuel, which can include almost any coal or waste fuel, is fluidized at 1450^0-1700^0F. Air is forced through the bed at 4- to 12-fps, a velocity sufficient to support the weight of the bed particles. When the bed is fully fluidized, it acts like boiling liquid. Although the burning coal typically makes up less than 2% of the fluidized bed, all the bed particles are heated quickly by the turbulence in the bed.

Figure 1 illustrates a typical fluidized bed combustion boiler. Boiler tubes submerged in the bed absorb heat directly from the turbulent solids. The heat converts water in the tubes to steam or superheats the steam. Because of the intimate contact of the boiler tubes with the fluidized bed, heat transfer is highly efficient and, consequently, less boiler tubing surface is needed to generate the same amount of steam as in a comparable conventional boiler. The high heat-transfer rates also permit lower combustion temperatures resulting in the formation of relatively low levels of NO_x, and, since the temperatures are below coal ash fusion temperatures, a variety of coals can be burned in a single design.

By mixing limestone with the coal, the majority of sulfur in the coal can be captured during the combustion process. The operating temperatures of the fluidized bed are particularly appropriate to the efficiency of the reaction to form calcium sulfite and sulfate. The furnace space above the bed, called the

Figure 1.

FLUID BED BOILER


Convection pass superheater
Flue gas system
Dust collector (cyclone)
Fly ash recycle system
Steam turbine
Fluidized bed
In-bed boiler tubes
Limestone feed system
Water circulation pump
Waste material drain system
Coal feed system
Air supply system

form calcium sulfite and sulfate. The furnace space above the bed, called the "freeboard", provides additional time for any unburned coal that escapes the bed to burn and to complete sulfur capture. Convective heat exchanger tube banks follow the furnace to further cool the gas and raise steam.

Over the last ten years, AFBC has steadily gained acceptance among small boiler operators. This acceptance has been due primarily to the boiler's ability to burn low-grade coals and waste fuels while meeting environmental regulations.

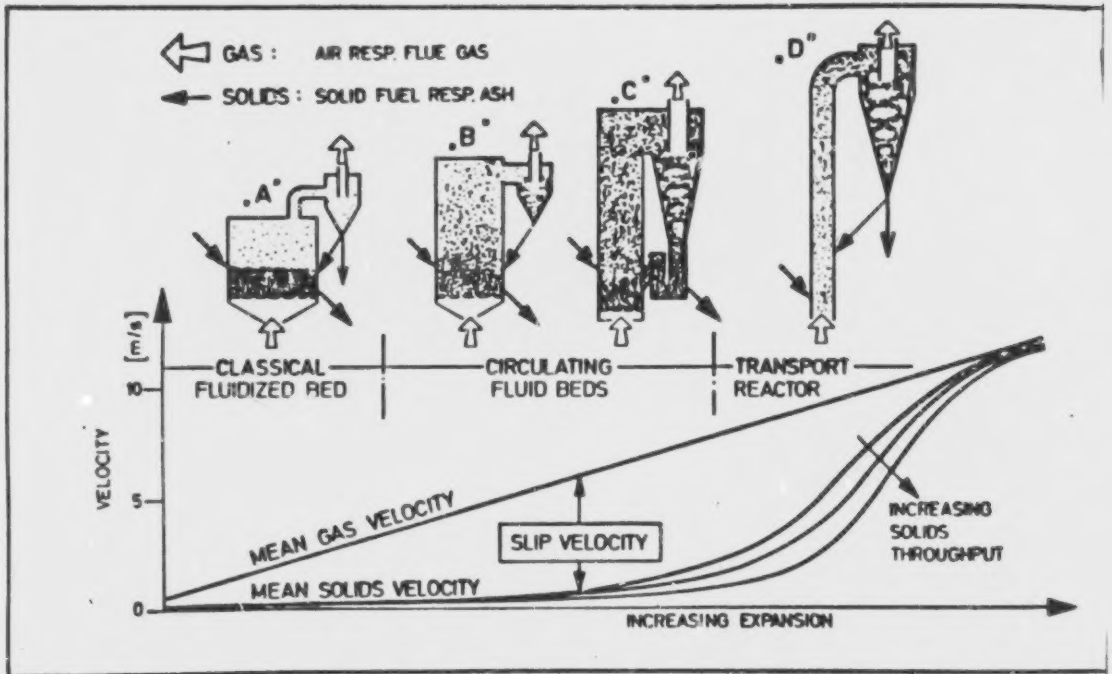
Currently 20 US boiler manufacturers offer first generation industrial AFBC units on a commercial basis. Approximately 70 such units have been installed and operated in the US and 30 are designed to burn coal. First generation AFBC technology is considered commercial for large industrial boiler applications of 200,000 pounds per hour of steam or more. However, significant opportunities exist for improving performance and reliability and for expanding the technology into both the smaller-scale industrial boiler markets and the much larger utility boiler applications.

Although these initial AFBC designs meet industry's need for process steam and space heating, they cannot be directly scaled up to the size required for utility power generation. Further private sector development of the technology has therefore been directed to making AFBC suitable for utility application. Because scale-up is a major issue, these efforts have involved progressively larger test boilers: a 2 MW development unit, a 20 MW pilot plant, and now three 110 to 160 MW commercial demonstration units.

Figure 2 indicates the fundamental effect of fluidization velocity on design. When the gas velocity through the fluidized bed is relatively low, solids are retained in the fluidized bed, hence, the term "stationary" or "fixed bed". Because much of the gas passes through a stationary bed in bubble-like pulses, the term "bubbling bed" is also used. Finally, because the original fluidized bed reactor designs are stationary or bubbling beds, the term "classical" is also used. If the velocity is increased to the point where most of the solids fed are lifted out of the fluidized bed, captured in a dust collector, and returned to the fluidized bed, it is termed a circulating bed. Because the relationship between gas velocity and particle size determines whether beds will bubble or circulate, it is possible to have a high velocity classical bed, operating at 15 feet per second with 1/8" particles, and a low velocity circulating bed, operating at 5 feet per second with 100 micron particles.

Hybrid systems may also be possible in which a circulating bed of fine particles co-exists with a bubbling bed of coarser particles where, due to staging of combustion air, a bubbling bed exists at the bottom of a furnace that feeds solids into a circulating bed above.

Bubbling and circulating fluidized bed boilers are at roughly equal stages of development as far as utility-scale designs are concerned. The operational and test data and design and cost estimates would not support the argument that operating costs could be substantially different. Any estimated cost differential may vanish or even reverse depending on experience in the larger units now operating or near completion. Fortunately, both types of FBCs have substantial promise, enthusiastic advocates and a growing list of practical


GAS : AIR RESP. FLUE GAS
SOLIDS : SOLID FUEL RESP. ASH
.A"
.B"
.C"
.D"
CLASSICAL FLUIDIZED RED
CIRCULATING FLUID BEDS
TRANSPORT REACTOR
VELOCITY [m/s]
10
5
0
MEAN GAS VELOCITY
MEAN SOLIDS VELOCITY
SLIP VELOCITY
INCREASING SOLIDS THROUGHPUT
INCREASING EXPANSION

BASIC COMBUSTION SYSTEMS FOR FINE PARTICLES

Figure 2.

applications that can provide the basis for confident scale-up. Fluidized bed boilers could also have several possible configurations, depending on such factors as the choice between natural or assisted circulation, the gas velocity in the bed, the coal and air distribution systems, and the method of achieving high combustion efficiency. The diversity of approaches has led to several complementary AFBC demonstrations. Their common objective is to provide the industry-wide experience necessary to confidently apply fluidized bed combustion as a new steam raising option.

Electric utilities specify new boilers that meet their basic efficiency and reliability requirements and expect hard evidence that these requirements will be met. Electric utilities will opt for fluidized bed boilers when their advantages outweigh the reliability risks of using a relative new technology.

Potential advantages of atmospheric fluidized bed combustion are:

o Emission control without scrubbers
o Dry solid waste
o Furnace design independent of ash content or properties
o No derating due to slagging or fouling
o Fuel flexibility
o Capital cost saving on power plant
o Ability to use low-grade fuels
o Improved cycling behavior

When the advantages listed above can be confidently achieved while meeting the basic utility boiler performance and reliability requirements, atmospheric fluidized bed boilers will compete effectively for new base-load and intermediate-load power plants. The program established and funded by the utility industry to implement the commercial demonstration of fluidized bed combustion indicates that this objective can be achieved this decade.

2. Pressurized Fluidized Bed Combustion (PFBC)

If the furnace is pressurized to a fireside pressure of 90-200 psig, the fluidized bed boilers system is called "pressurized fluidized bed combustion" or PFBC. Combustion products from this system can be used to drive a gas turbine. The hot combustion gases pass through a particulate removal system, then through the power recovery expander. Next, they move through a heat recovery steam generator and are finally exhausted to atmosphere. This use of the PFBC boiler in a combined cycle system to produce both steam and hot pressurized flue gas to drive a separate turbine-generator is a highly energy efficient use of coal for power generation. Operation at elevated pressure reduces combustor size and enhances several performance parameters. While substantial development progress has occurred in recent years in Europe, PFBC is not yet as technically mature as AFBC, represents a more revolutionary change in technology, and involves more risk today.

To reduce this risk, an alternative PFBC power cycle, called the PFBC turbocharged boiler, uses convective heat exchangers to extract sufficient energy to reduce the gas turbine inlet temperature to less than 1000°F. This lower temperature allows a current technology gas clean-up system to remove particulates from the combustion gases, minimizes turbine blade corrosion, avoids expensive high-temperature gas piping, and eliminates the need for a heat recuperation system and a final gas cleaning system in the turbine exhaust. The gas turbine outlet gas exhausts directly to the stack. The turbine under these gas conditions provides only power sufficient to drive the air compressor. The projected overall system efficiency is 37%, about 2% less than the combined-cycle system. However, it is an attractive candidate for PFBC power plants because of reduced technical risk, expected increase in plant reliability over the PFBC combined cycle, reduced capital cost, and the inherent ability to be modularized. PFBC boilers thus can respond effectively to the trend toward smaller new unit size plus utility priority on uprating the capacity of existing units to bring generation on line quickly and at the lowest cost.

These advantages can translate into an effective reduction in capital cost by better matching load growth and reduced construction work in progress (CWIP). These two factors have been evaluated by the utility industry, and it was found that the benefits of such modular technologies can produce an equivalent capital cost savings of about 25%. PFBC provides the opportunity to add these advantages to the inherent fuel flexibility and environmental control capabilities of atmospheric fluidized bed combustion.

As a result, development emphasis is being placed on PFBC boilers which can provide shop-fabricated, barge transportable, steam generation modules. These may be rapidly field-erected to provide the desired uprating in unit sizes of 150 MW to 250 MW. This approach can also use coal to replace or increase the capacity of existing oil- or gas-fired plants while meeting stringent siting and environmental control constraints. It also provides the lowest potential busbar energy cost of any coal-fired power generation option now under development.

Because of the reduced technical risk associated with the turbocharged boiler concept, it is likely that PFBC commercialization can be accelerated to 1990. The speedup could happen because all technical efforts could be focused on the critical combustor and solids feeding/discharge problems instead of being diffused among the other technical challenges of gas cleaning, conveying, and expansion at the higher temperatures of the combined cycle. Future PFBC plants could evolve into a combined cycle configuration by incrementally raising the firing temperature of the turbine as experience is gained.

III. OUTLOOK FOR REQUIREMENTS FOR 2020

By the year 2020, even with a forecast of only a 3% average electricity demand growth rate, utility generating capability can be expected to more than double to 1,600,000 MW. With the current public perception of nuclear power, it is likely that this growth must depend primarily on coal for the foreseeable future.

Technology being developed today to satisfy tomorrow's generation needs must, however, be responsive to the new operating environment of the electric utility industry. As utilities shifted from being declining cost producers to increasing cost producers in the early 1970s, regulatory attempts to control these costs have stepped up. The resulting widespread penalization of excess capacity has led to a reversal in generation planning to virtually eliminate capacity additions for many utilities. One approach to reducing the risks of new capacity is to construct smaller coal-fired plants that take less time to get on line (thus reducing the planning horizon and also more closely matching lower growth rates).

Successful development and application of FBC provides the opportunity to reduce utility industry capital investment, control fuel costs and, perhaps even more importantly, resolve the various environmental conflicts which impede the use of coal.

It is unrealistic to think, however, that FBC generation technology will supercede conventional pulverized coal plants overnight. Rather, development has reached the point where FBC is at least competitive in performance and cost and can show specific advantages even in first generation application. While this provides a basis for commercial demonstration, ultimate market penetration will depend on:

- o Proven reliability
- o Continued performance improvement through application

For example, a 20% reduction in capital and busbar energy costs may be achievable with increased efficiency and emission control, even in first generation applications.

TABLE 1

EMISSIONS CONTROL POTENTIAL

Technology	SO_x % Removal	NO_x lb/10^6 BTU
Conv. PC/FGD*	90	0.5-0.6
AFBC	90-95	0.2
PFBC	90-95	0.1

*New Source Performance Standards

In addition to providing the potential to reduce capital and busbar energy costs, these options should provide reduced construction time plus higher efficiency and availability. Perhaps most importantly they have, as newly developed technologies, the potential for continued refinement of all these advantages as their commercial application matures. By comparison, conventional pulverized coal technology is nearing the end of its development potential.

The utility industry's uncertain future with respect to emission regulations, demand growth and financial climate is expected to persist for some time. Therefore, the need for clean, easy to site, short lead time plants that can be economically built in smaller sizes is expected to be a persistent trend.

There is also great diversity among utilities in their generating mix, local emission requirements, fuel availability and cost. Hence, no single technology design is expected to satisfy all situations. A flexible and diverse array of power generating options is essential to maintain a healthy and responsive electric utility industry in the 1990s and beyond. Table 2 compares alternate FBC technologies in terms of key characteristics desirable to the utility industry.

TABLE 2

QUALITATIVE COMPARISON OF CHARACTERISTICS

Characteristics	Conv. PC/FGD	AFBC	Turbo-Charged PFBC	Combined Cycle PFBC
Economical and Small Sizes	--	+	++	++
Fuel Flexibility	--	++	+	+
Low Emissions	--	+	++	++
Short Construction Time	--	+	++	++
Reduced Resource Use (water, etc.)	--	+	+	+
Waste Byproducts	--	+	+	+
Heat Rate (BTU/kWhr)	9860	9640	9400	8470
Capital Coast (1984 $/kW)	1150	985	750*	850*
Levelized Busbar Cost (Mills/kWhr)	90	75	65*	65*

* Includes equivalent value of modularity

LEGEND: -- Same as present conventional pulverized coal technology
+ Better than present
++ Much better than present

The key issue which must be resolved before large scale application of these options can occur is their long term reliability under utility operating conditions. The development and demonstration of these options must therefore occur at sufficiently large scale to verify their commercial reliability.

The continuity and success of the previous combined Federal/private development effort in AFBC has reduced the risk to the point where pioneer AFBC demonstrations are feasible through private sponsorship. This effort thus provides a successful prototype for industry and government collaboration in other areas of coal utilization R&D. Unfortunately, unless similar Federal/private collaboration is rapidly achieved to reduce the risks for PFBC, the demonstration and commercial application of this important coal utilization option will be stalled in the US.

If successful commercial demonstration of both AFBC and PFBC are achieved by 1990, then the following estimate of FBC utility market penetration is offered.

TABLE 3

POTENTIAL FBC MARKET PENETRATION (10^3 MW)

	1990	2000	2010	2020
Total Generating Capacity	700	950	1250	1600
Total Coal-Generating Capacity	300	500	700	900
o AFBC Capacity	0.5	50	150	250
o PFBC Capacity	0	25	100	200

IV. CURRENT R&D

1. AFBC

The Development of AFBC for industrial application in the US has been the primary DOE focus. This has resulted in a variety of industrial demonstrations. These include AFBC boilers at the Great Lakes Naval Station, Georgetown University, East Stroudsburg State College, and the City of Wilkes-Barre, Pennsylvania.

Ten years ago the first attempt was made to operate a 30 MW AFBC boiler at a US electric utility power plant. At the time, this was a factor of 60 scale-up from the available process development pilots. Operation of this unit clearly indicated the directions needed for development. In the ensuing ten years, experience with AFBC for steam generation has advanced with the construction of many industrial-scale boilers around the world. To meet the additional requirements of utility application, R&D led by EPRI and TVA has included several key areas: investigation of fundamental fluidization phenomena; materials assessment as applied to high pressure and temperature steam generation; process turndown and load following control; development of an extensive AFBC process data base; and scale-up of the process toward utility-size applications involving 2 MW and 20 MW pilot facilities.

The 6 ft-by-6-ft fluidized bed cross section and high freeboard of the 2 MW process development facility, known as the "6 x 6", was designed to simulate the large bed area and long residence time that would be typical of utility-scale units. An extensive parametric testing program begun in 1977 led to design modifications for improving the process to meet utility efficiency requirements. An important modification was the addition of a subsystem to recycle the collected flyash back to the fluidized bed. The successful testing at the 6 x 6 provided the basis for proceeding to a larger utility design test unit.

In 1979, the TVA and EPRI developed plans for a 20 MW AFBC pilot plant, a tenfold scaleup over the 2 MW 6 x 6 facility. This engineering pilot unit, funded and built by TVA at their Shawnee steam plant in Paducah, Kentucky, was designed to simulate utility power plant operating conditions and mechanical features. Construction of the pilot plant was completed in May 1982. Over 7000 hours of test operations have since been accumulated on the facility.

These R&D efforts have led to the recent initiation of AFBC demonstration projects that will integrate commercial AFBC steam generators into utility power plants.

Three such complementary utility demonstrations are now proceeding under private sector leadership. These are described in Table 4.

The results of these demonstrations are intended to provide the technical, performance, and economic basis for commercial, utility application of AFBC steam generating technology. The major phases of the projects will include (a) development of detailed designs for a specific AFBC application in a utility power plant, (b) fabrication and erection of the AFBC steam generator and required balance of plant systems, (c) a three year or more test program, with the AFBC, planned and implemented by EPRI, to demonstrate performance and reliability over the range of operating conditions, and (d) operation on economic dispatch of the remaining life of the plant.

The TVA/Duke Power/EPRI/State of Kentucky demonstration will build a new AFBC boiler to repower and extend the life of an existing 160 MW steam turbine/generator at the TVA Shawnee Power Station. This is the primary demonstration effort to achieve a confident basis for applying AFBC as a utility generating alternative by the 1990s. Availability of $30 million in DOE funding has added to the prompt financial closure of this project.

The Northern States Power AFBC Demonstration provides a retrofittable utility option to meet SO_x and NO_x New Source Performance Standards (NSPS) as well as reduce sensitivity to coal quality at existing, older power plants. Here, an existing 100 MW_e pulverized coal boiler will be converted to AFBC while also increasing its capacity to 125 MW and extending plant life by an expected 25 years. This conversion will also change the plant from base to peaking duty. This demonstration will be built and operated as a commercial effort. As a result, the cost will be offset by the resulting increase in generating capacity, fuel flexibility and plant life, thus making it a more cost-effective option than flue gas desulfurization. An examination of the utility boiler population indicates that there are a substantial number of candidate utility boilers for similar AFBC conversions. They total about 20,000 MW in 200 units built primarily during the period of 1945-1965.

The Colorado-Ute Project provides yet another option. Here, a new 110 MW circulating AFBC boiler will be built to repower an existing 40 MW steam turbine/generator as well as drive a new 70 MW steam turbine/generator. This AFBC boiler offered by US manufacturers, but reflecting a European design base, will provide a useful direct comparison, in terms of performance and reliability, to the bubbling bed designs being installed by TVA and Northern States Power.

TABLE 4

PIONEER UTILITY FLUIDIZED-BED COMBUSTION DEMONSTRATIONS

	TVA/DUKE	NSP	Colorado-Ute
Location	Paducah, KY	Minneapolis, MN	Nucla, CO
Size (e)	160	125	110
FBC Type	Bubbling	Bubbling	Circulating
Scope	Add-on Boiler	Boiler Conversion	Add-on Boiler & T/G
Coal	High S Bituminous	Low S Subbituminous	Low S, High Ash Bituminous
Startup	1988	1986	1988
Steam Conditions	Reheat	No reheat	No Reheat
Feed Systems	Underbed	Overbed	In-Bed
Dust Collector	baghouse	ESP	baghouse
Structural Design	Top Support	Top Support & Bottom Support	Top Support
Dispatch Schedule	Base Load, Some Cycling	2-Shift, 5-day Cycle	Base Load
Startups Per Year	20	250	<10
Boiler Supplier	Combustion Engineering	Foster-Wheeler	Pyropower (Ahlstrom)

The confidence to proceed with these demonstrations is based on resolution of a variety of performance and reliability uncertainties at the 2 MW and 20 MW pilot facilities. This and other supporting R&D for utility AFBC application has been primarily funded by EPRI over the past decade at an average annual commitment of about $10 million. This effort has:

- Developed reliable heat transfer data
- Quantified boiler tube corrosion rates for materials selection
- Achieved New Source Performance Standards for SO_2, NO_x and particulate
- Achieved acceptable solids feed and system control performance
- Established commercial boiler design guidelines
- characterized specific fuels and sorbents.

The status of specific AFBC technology issues may be summarized as follows:

- Turndown and Load Following--Single-bed performance results indicate that the turndown and control goals are achievable when scaling to larger, multiple bed AFBC configurations. The rate at which load can be safely changed has reached 5% per minute. Transient response data from the 20 MW pilot will enable control systems to be designed for fast output changes with multiple beds.

- Coal Feeding--Various configurations of overbed and underbed feed systems are being considered, on the basis of cost and reliability, for application in the commercial demonstrations. Overbed feeding involves the use of spreader-stokers that throw the coal over the top of the bed where the furnace pressure is neutral. The system is relatively simple, containing few components and these are not subjected to severe duty conditions. The overbed system may, however, require coal-fines control to achieve high combustion efficiency with less reactive coals. By comparison underbed feed system designs are sensitive to erosion and plugging but have demonstrated generally higher process performance. Their complexity arises from the need to split the feed stream into several separate streams to distribute coal at the case of the bed. Design alternatives incorporating improved coal sizing control, drying and pneumatic sealing seem to have resolved the pressing reliability issues and will be used in the TVA/Duke Power/EPRI AFBC demonstration project.

- Materials--Corrosion and erosion of tubes immersed in the fluidized bed and erosion of convection pass surface have been concerns. From a corrosion perspective, tube material selection criteria have been developed for evaporator, superheater and surfaces. Very few erosion incidents of in-bed tubes have been reported at the 2 MW and 20 MW pilot units. In all cases, there were localized phenomena caused by jetting or non-uniform tube geometries. A data base has been compiled and is resulting in bed design guidelines. Additional research to extend these data and guidelines is encouraged.

- Effect of Scale on Performance--Scale effects due to longer freeboard residence time and turbulence have positive effects on performance. For low-sulfur, high reactivity coal, carbon burnout and SO_2 capture performance is less sensitive to these scale effects as well as feed point spacing, recycle rates and coal/limestone particle size. On the other hand, these design variables become far more important with the less reactive, eastern bituminous coals. Substantial effort has been directed to design requirements at the 20 MW pilot and the resulting guidelines will provide the basis for the TVA/Duke Power/EPRI demonstration. Testing has concentrated on investigating the effects of recycle rate while maintaining near constant bed depth, temperature and velocity. Two approaches to improved combustion efficiency are being pursued. First, increasing the recycle rate and second, increasing the collection efficiency of the recycle cyclones. Combustion efficiency of at least 98% has been achieved with both eastern and western coals using these guidelines.

- Sulfur retention--The capture of SO_2 in a fluidized bed boiler is primarily dependent on the amount of sorbent limestone in the boiler, sorbent surface area, and residence time (time in the unit when reactions can take place. Operating parameters that control these factors are the limestone-to-sulfur ratio expressed as the Ca/S molar ratio, as well as recycle rate, bed depth, temperature, freeboard height and superficial velocity. Since the Ca/S molar ratio has the greatest impact on sulfur retention, testing has concentrated on investigating the effects of Ca/S and char recycle on sulfur capture while again maintaining near constant bed depth, temperature, and superficial velocity.

Results to date indicate that 90% sulfur retention can be reached using underbed feed with a Ca/S ratio of 2 to 2.5 and recycle ratio of 2 to 3. The overbed coal feed results show the same trend but with a slight reduction in performance. Methods to further improve sulfur capture are presently being evaluated. These include enhanced freeboard residence time and turbulence, both of which are natural consequences of scale. Another process improvement under current development is the grinding and reinjection of the waste sulfated limestone. Grinding should free up the available limestone in the case of the particles and, by reinjection make it available for sulfation. Preliminary analysis shows that overall calcium utilization in excess of 50% is achievable.

In recent years, circulating AFB (CAFB) has emerged as a promising candidate for industrial and utility coal-fired boiler. Circulating AFB is characterized by high superficial gas velocity and a high solids recirculating rate through the bed. Lurgi, in West Germany, first introduced circulating AFB commercially in the early 1970s for the chemical industry. At the same time, the Ahlstrom Company in Finland started an active R&D program to commercialize circulating AFB for coal and low-grade fuels. In the US, Battelle-Columbus Laboratory in Ohio introduced the related Multisolid Fluidized Bed Boiler concept in 1978.

Industrial CFBC coal-fired boilers up to 100 MW are being marketed in the US by Pyropower-Ahlstrom, Combustion Engineering - Lurgi, and Babcock & Wilcox - Studsvik, Energitechnik.

CAFB designs offer further potential to simplify solids feeding, improve carbon utilization, reduce limestone requirements and achieve greater NO_x reduction. The need, however, to circulate the total bed inventory at higher velocities creates a variety of offsetting technical issues that must be resolved. Development and demonstration programs for circulating AFB should therefore focus on determining penetration of the secondary air through a gas-solids mixture with a density over 1 lb/ft^3, the performance and reliability of large, parallel hot cyclones, and reduction of heat loss from large refractory-lined components. Circulating AFBC designs may also be improved by applying aspects of bubbling beds such as the water-cooled air distributor.

2. PFBC

The potential benefits of PFBC for power generation were first investigated in 1969 at the British Coal Utilization Research Association (BCURA). Subsequently, a number of other pilot-scale combustors were operated, originally with EPA support in the US. In addition to the BCURA facility, the Exxon "Miniplant" and the Argonne National Laboratory facilities have been especially important. Both the BCURA and "miniplant" incorporated cascades of turbine blades and have indicated the potential for future gas turbine operation. Two larger PFBC facilities in the US were operated during the 1970s in conjunction with gas turbines. The first was an adiabatic PFBC combustor by Combustion Power Inc., and the second was a small air heater PFBC unit by Curtis-Wright.

Although the fundamental effects of pressure on fluidization and combustion are not fully understood, certain enhanced characteristics relative to AFBC have become apparent, based on test facility experience.

- Combustion Efficiency--The superficial gas residence time or the excess air is so great that combustion efficiency, in practice, will always be greater than 99%. Factors which also assist in attaining these high efficiencies are the better gas-solids contacting brought about by pressure.

- Heat Transfer--Because fluidizing velocities (and therefore bed particle sizes) are typically lower in PFBC than atmospheric units, the heat transfer coefficients are correspondingly higher.

- Sulfur Retention--Good sulfur retention efficiency depends on the development of porosity in the sorbent particle. At high pressure the effectiveness of limestone is reduced because calcination, on which porosity depends, is curtailed. On the other hand, dolomites become much more effective since they undergo two stages of calcination. The "half-calcination", reaction $CaCO_3 + MgCO_3 = (CaCO_3 + MgO) + CO_2$ proceeds rapidly, creating porosity while curtailing decrepitation.

- NO_x Emission--Experimental data have shown that increasing pressure reduces the NO_x emission approximately in proportion to the square root of pressure.

There were a remarkably large number of approaches to the development of PFBC. Table 5 lists the major technical issues and different potential solutions. Although the turbocharged PFBC boiler has less technical uncertainty than its combined-cycle counterpart, considerable development is still required before the commercial potential of this option can be realized. As indicated in Table 6, this effort centers on the PFBC boiler and involves the design base for the tube bundles in the bed as well as feeding, ash handling, hot gas cleanup and control of the PFBC boiler system. Table 7 further describes these development issues together with available facilities for their resolution.

PFBC development efforts are planned by two US boiler manufacturers. Babcock and Wilcox (B&W) and Foster Wheeler are proposing to design and supply in-bed heat transfer tube bundles for performance and reliability testing at the Grimethorpe PFBC Test Facility, if access can be obtained. An alternative approach with Combustion Engineering relies on a circulating PFBC boiler to eliminate the need for in-bed heat transfer tubes. Unfortunately, at the present time, no proof-of-concept PFBC facility for such a circulating bed design exists. These efforts are a key stepping stone to implementing planned PFBC demonstration projects with the utility industry.

TABLE 5
TECHNICAL ISSUES FOR PRESSURIZED FLUIDIZED BED COMBUSTORS

ISSUES	ALTERNATE APPROACHES
1. Feeding Coal Across Pressure Barrier	1. A. Slurry Pump B. Lock Hoppers C. Dry Solids Pump
2. Combustor Design	2. A. Circulating Bed/Separate Fluidized-Bed Heat Exchanger B. Bubbling Bed Combustor with In-Bed Tubes C. Vertical Air Tubes
3. Hot-Gas Cleanup	3. A. Cyclones in Series B. Electrostatic Precipitators C. Ceramic Fabric Filter D. Granular/Electrostatic Filter E. Rigid Ceramic Filter
4. Cold-Gas Cleanup	4. A. Do it all hot and at pressure B. Protect gas turbine. Add cold ESP or baghouse
5. Sulfur Sorbent	5. A. Oxidizing-Bed 1. Dolomite 2. Calcined Limestone B. Reducing Bed Limestone
6. Load Following	6. A. Bed-Slumping B. Bed Removal to Satellite Vessel C. Solids Circulation Rate Reduction to Satallite Heat Exchanger
7. Pressure Ratio (which affects steam/gas turbine work split)	7. A. As low as 6:1 B. As high as 30:1
8. First Cyclone Location	8. A. Within Combustor Vessel (large, but few, vessels) B. Separate vessel(s) (Smaller, but more, vessels)
9. Gas Turbine Development	9. A. None; operate existing machine off-design B. Modify blade path, harden blades C. Optimize for maximum efficiency
10. Turbine Erosion Protection	10. A. Use "dirty gas" machine, i.e., cat cracker machine B. Clean gas to < 10 ppm or +5 u particles - clad or coat blades
11. Turbine Corrosion Protection	11. A. Clad blades B. Feed alkali "getter" C. Run turbocharged boiler condition

TABLE 6

TURBOCHARGED BOILER/COMBINED CYCLE PFBC COMPARISON

Issue	Status for: Combined Cycle	Status for: Turbocharged Boiler
Removal of 99% of particulate		
at high temperature	>1500°F	>1000°F
at high pressure	Yes	Yes
Protection of gas turbines		
from remaining particles:	Yes	Yes
from alkali vapors	Yes	No
Tube materials and design to avoid corrosion/erosion	Yes	Yes
Controls for matching high inertia PFBC and low inertia gas turbine	Yes	No
Gas turbine overspeed protection	Yes	No
Cool ash for depressurization	Yes	No
Need to use dolomite	Yes	Yes
Scale-up to utility size	Yes	Yes

Unfortunately, all of the development facilities indicated in Table 7 are located in Europe, which makes communication and access difficult at best. As a result, PFBC development in the US has been largely paced by access to results from the 23 MW IEA Grimethorpe facility originally built and operated jointly by the UK, US, and West Germany. This IEA sponsorship formally concluded in 1984 with any continued operation to be principally funded by the National Coal Board (NCB) and Central Electricity Generating Board (CEGB) of the US. Continued DOE participation is encouraged but remains uncertain.

This continued Grimethorpe experimental program, to be funded by the UK at a cost of $30 million, is organized as follows:

1. Test Series A-1 (0-15 months)
   - Operation at 0.8 m/sec fluidizing velocity with new tube bank
   - Evaluation of tube bank over 1000 hours
   - Study combustion efficiency, heat transfer, SO_3 and NO_x production, and dust emission/elutriation/particle attrition as functions of operational parameters
   - Component evaluation and development
   - Dynamic and combustion response
   - Operation at a higher fluidizing velocity
2. Test Series A-2 (26-32 months - after facility modification)
   - New tube bank if required by A-1 results
   - Part load strategy
   - Effect of feed nozzles
   - Effects of high chlorine coal
   - Improved hot gas cleanup
3. Other activities, still depending on co-funding, includes:
   - Hot and cold modeling of tube bank designs (including US)
   - Fines recycling and feed system design studies
   - Staged combustion trials at CRE Stoke Orchard
   - Extended materials studies.
   - Ash removal
   - Test Series B, including installation of a gas turbine for combined cycle development

DOE has also constructed a unique and complementary 13 MW PFBC pilot facility with Curtiss-Wright in New Jersey. The unique capability of this facility is that it provides a complete PFBC system, that is, a combined combustor and gas turbine and one directly available to US developers. Although the combustor is used to heat air rather than steam, the system nevertheless can effectively address several issues limiting confident PFBC system scale-up as follows:

- o Combustor operation and performance
- o Solids feeding and discharge
- o Hot gas cleanup technology capable of operating reliably beyond the efficiency of inertial separators
- o Integrated PFBC boiler/gas turbine operation and control
- o System availability and operability under utility conditions

Unfortunately, DOE has decided to dismantle this $65 million facility before it had a chance to operate. This decision was apparently based on the operating cost and uncertain modification needs of the facility to achieve reliable operation.

American Electric Power (AEP), working with STAL Laval and Deutsche Babcock, has also made progress toward the development of a compact, combined-cycle PFBC system. A 15 MWt component test facility is now operational in Malmo, Sweden, as indicated in Table 7.

At the Aachen Technical University (West Germany), a commercial bubbling bed PFBC is scheduled to start-up in May 1985 in order to generate electricity and steam heating for the University. This 40 MWe plant is a true turbocharged boiler operating at variable pressure from about 1 to 3.8 atmospheres. In addition to providing power for the University, considerable experimental work will also be performed. The equipment is manufactured and installed by Steinmuller.

In support of these PFBC development efforts, EPRI has emphasized R&D on materials and hot gas cleanup. Tests of boiler tubing have shown relatively low corrosion rates for most boiler alloys. Superheater and reheater tubes will likely be all austenitic stainless steel in order to avoid dissimilar metal welds in the furnace. Erosion has been identified as a serious problem in the pilot unit at Grimethorpe in England. An effort to protect the tubes via addition of studs and fins has not been very successful. However, an intense parallel effort to understand the cause and eliminate the problem is underway in cooperation with Grimethorpe at the US boiler manufacturers.

EPRI has also funded tests at two PFBC gas turbine simulators to provide the data needed to select turbine blade materials. These tests have confirmed expectations that damage to most alloys is severe at high dust loadings. Some good candidate claddings have been identified, however. The main finding has been the importance of hot-gas cleanup in removing the damaging particulate and the importance of maintaining reduced turbine inlet temperature.

Both woven ceramic fabric bags and a rigid silicon-carbide "candle" have shown excellent filtration and appear to be rugged enough to survive the PFBC environment. A test of both is currently planned to determine long-term reliability. Finally, tests sponsored by the US DOE have shown that an electrostatic precipitator (ESP) would be expected to perform efficiently at the gas conditions of the turbocharged boiler. Brown Boveri and Research Cottrell are also evaluating the practical aspects of the ESP for turbocharged boiler application.

In 1982, an EPRI study by Brown Boveri identified the PFBC turbocharged boiler as an attractive alternative to the combined cycle system more commonly associated with PFBC systems. Efforts have been initiated by EPRI, individual utilities, and boiler and turbine manufacturers to design engineering prototypes of the turbocharged boiler based on these results. These studies have considered both bubbling and circulating PFBC designs. The latter eliminates in-bed heat transfer surface, thus avoiding the troublesome erosion-corrosion problems experienced to date in bubbling bed designs and also facilitating part-load control.

TABLE 7

KEY ACTIVITIES OF LARGE PFBC FACILITIES

ISSUE	
1. Combustion	Grimethorpe - NCB/CEGB Malmo - STAL Laval Aachen - Technical Hochschule
o Process Performance	
- Comb. Efficiency	
- SOx	
- NO_x	
2. Solid Handling	Grimethorpe Malmo
o Preparation	
o Pressurization/Depressurization	
o Feeding/Distribution	
o Cooling	
3. Gas Filtration	Grimethorpe Aachen
o Filter Media	
- Collection Efficiency	
- Life	
- Pressure Drop	
- Cleanability	
4. Gas Turbine	Grimethorpe (static) Malmo (rotating)
o Erosion	
o Corrosion	
o Fouling	
o Turndown	
- Variable Speed	
- Variable Flow	

These PFBC design studies have confirmed the potential for a significant reduction in capital costs over pulverized coal systems with flue gas desulfurization. One GE/B&S study was made site specific to Florida Power and Lights' (FP&L) Palatka-2 Plant, a retired 80 MW_e plant located in North Central Florida. GE, B&W and FP&L have continued to investigate this concept, including sorbent testing and cold flow "in-bed" tube erosion tests in the CURL PFB test facility in England and a hot gas cleanup system at GE's PFBC facility in Malta, New York. The ultimate goal of this work is the demonstration of a full-scale (100 MW_e) module on a utility system.

V. COMMENTS ON R&D PROGRAM

1. AFBC

In the past 20 years, the Federal Government through DOE, EPA, TVA, and predecessor agencies has funded approximately $500 million in research, development and demonstration efforts on fluidized bed technology and has co-sponsored seven international conferences. In 1978, Federal fluidized bed boiler development responsibility for industrial and pressurized utility application was assumed by DOE's predecessor, ERDA, while development responsibility for atmospheric utility application was assumed by TVA.

Based on the ERDA/DOE effort, first generation AFBC technology is considered commercial for large industrial boiler applications. Thus, DOE's role has been redirected away from AFBC demonstration and commercialization activities towards long-term, high-risk technology research which industry is not expected to fund. DOE is currently pursuing advanced concepts of second generation AFBC technology to improve economics and performance for small boiler application.

Second generation AFB technology is still in the applied research stage of development. Conceptual studies for seven advanced AFB units were completed in March 1983. These seven concepts are:

o Battelle	a. High velocity combustor and b. Spouted combustor
o A.D. Little	Pulsed bed
o Energy & Environmental Eng. Inc.	Staged cascade FBC
o Westinghouse	Draft tube combustor
o Aerojet Energy Conversion Col	Moving distributor
o M.W. Kellogg	Internal circulating bed boiler

The DOE plans to move the two most promising techniques into proof-of-concept testing. This stage of development would be approximately 50-1500 pounds steam per hour, with tests conducted over a 1.5 year duration. A subsequent pilot plant unit of approximately 10,000 pounds of steam per hour would probably be necessary before second generation AFB technology could be introduced commercially. However, no large demonstration plant is considered necessary by DOE if all technical milestones are achieved.

An additional program area is concerned with support projects and studies including: risk, market and environmental studies; instrumentation and equipment studies; agglomeration and low rank coal studies; erosion and bed dynamics; modeling; data analysis and dissemination.

During 1985, the DOE AFBC R&D effort will specifically include:

- o Support for the TVA AFBC demonstration
- o Bench scale testing of two advanced AFBC concepts
- o AFBC fluidization research and heat transfer studies
- o AFBC model validation
- o Investigation of AFBC pollutant formation, transport and fate
- o Upgrade central AFBC data base.

Under the decenteralized DOE management approach, the Morgantown Energy Technology Center (METC) is the designated lead center for the AFBC Technology Program. The FY 1985 DOE request for AFBC totals only $17.5 million, of which $15 million is for the TVA 160 MW AFBC demonstration.

While the objectives of the DOE AFBC program are comprehensive, the level of funding is entirely inadequate to meet these objectives. Based on the large private sector effort which is stimulating a variety of AFBC process designs, the DOE effort would better focus on the generic issues constraining AFBC rather than proprietary "second generation" designs. These R&D needs reflect the operational problems encountered in AFBC and relate to:

- o solids handling
- o feed system design
- o recycle design
- o heat and mass transfer phenomena
- o freeboard design and performance
- o dynamic reaction kinetics and load control
- o combustion and pollution control characterization for the range of fuels
- o optimization of pollution control.

This latter category should include:

- Extensive chemical and physical characterization of solid wastes from all FBC process streams
- Utilization of FBC waste products, e.g. to fixate fly ash or as scrubber reagent.
- Development of solid waste management equipment meeting the unique characteristics of FBC waste.

- Separation of excess reagent from FBC ash.

In addition, US experience in circulating AFB development is very limited. Specific areas of uncertainty requiring additional development attention are the high combustion gas velocity, the high solids recirculation rates, and the lack of internal heat transfer surface in the combustor. The lack of internal heat transfer surface may pose the biggest problem for scale-up, especially for utility size boilers. Since the percentage of heat removed from the combustion zone diminishes as the combustor size increases, this may constrain circulating AFBs to some maximum practical size, unless some means can be found for introducing internal cooling surfaces without the risk of erosion.

Such an expanded DOE support effort for both industrial and utility AFBC applications is estimated to require about $20 million per-year for at least five years and would involve modifications and instrumentation of a variety of existing research, pilot and commercial AFBC facilities. Equivalent private sector cost sharing for such a DOE initiative is considered realistically available and appropriate to ensure rapid technology transfer to commercial application. In addition, support for the demonstration of circulating AFBC in both industrial and utility application is encouraged.

2. PFBC

Because PFBC is at an earlier, higher risk state of development, its R&D demands are necessarily greater today. Unfortunately, DOE's efforts in the area have eroded drastically to a probable total of $3.5 million in 1985. This is about one-fourth the 1983 PFBC appropriation. Although the stated goal of DOE sponsored activities is to "develop a US technology base for PFBC scientific and engineering technology through proof-of-concept and to support private sector efforts to commercialize the technology," the available resources are not consistent with this goal.

Historically, DOE PFBC development and testing has focused on the IEA/Grimethorpe facility and the supporting Coal Utilization Research Laboratory (previously BCURA). Fundamental research on combustion characterizations has been performed at New York University and General Electric. PFBC technology activities are continuing at a low-level with in-house efforts to investigate fluidization regimes under pressure and concepts on the PFBC loop bed combustor at Morgantown. Table 8 summarizes the major DOE PFBC projects and facilities.

TABLE 8

MAJOR DOE PFBC PROJECTS

o CURL Research Facility (now CRE Stoke Orchard)	5 ATM 2'x4'; 20 ATM 1'x1' Test Rigs	Component Problem Identification	Coal Water and Large Size Coal Combustion Testing. Elevated Pressure Combustion Testing in Progress, Erosion Mechanism March 1984.
o IEA Grimethorpe Facility	12 ATM 25 MW_e Boiler	Major Facility For Component Test	Test Series I Complete Dec. 1981 Test Series II Complete May 1984 Final Reports December 1984.
o Small Gas Turbine Test Rig (Curtis-Wright)	7 ATM 3' Dia Test Rig	Cleanup/Turbine Test. Data Vertical Tube Air	Test Began in FY 1978. Completed 100 hr Turbine Test - Dec. 1979. Hot Gas Cleanup Subsystem Testing Complete. Unit Being Dismantled and Relocated to METC.
o Combined Cycle Pilot Plant (Curtis-Wright)	7 ATM 13 MW_e	Major Integrated System Test Facility	Construction Completed. Plant Being Dismantled Without Any Operating Experience.
o NYU Test Unit	10 ATM 30' Dia	Combustion Characterization, Bed Geometry	Lignite and Low Grade Fuel Combustion Testing Bed Geometry Testing in Progress.
o GE-LTMT	10 ATM 1' Dia Test Rig	Gas Turbine Materials Test Facility	Long-Term Gas Turbine Materials Corrosion/Erosion Test Programs. Work stopped and rig demolished.

Several critical issues remain which pface the demonstration of commercial PFBC power plants and which should be the focus of a comprehensive DOE effort. These issues are:

1. Plant cycle decisions: a rational basis for bed temperature, cooling method and working-fluid cycle.
2. Boiler: erosion/corrosion of in-bed and in-gas stream components.
3. Boiler: shell configuration and bubbling versus circulating design.
4. Coal Feeding: development of coal pumps or coal/water slurry feed system to replace lock hoppers.
5. Ash cooling for safe decompression.
6. Plant control: startup, load following, and gas turbine overspeed control.
7. Scale-up of plant components.
8. Hot gas cleanup performance and gas-turbine tolerance to corrodents/erodents/fouling.
9. Reduce dependence on dolomitic limestone for SO_2 capture.
10. Performance characterization for the range of fuels and sorbents.

All of these issues can be resolved over the next five years but require accelerated DOE support for operation of available integrated pilot plants and process development units. Since the principal application of PFBC systems is electric utilities, proof-of-concept should be based on facilities in the 10 to 25 MW_e size range (equivalent to 100,000 to 250,000 lb per hr of steam). The only existing facilities meeting this criterion are the Grimethorpe facility and the Wood-Ridge (Curtis-Wright) pilot plant.

Continued US participation in the operation of Grimethorpe has been encouraged by the UK and should be implemented jointly by DOE and EPRI. The total cost of US participation in the next phase (1985-1987) of testing is about $18 million. This participation should emphasize qualification of improved hot gas cleanup technology and testing of heat transfer tube bundles for performance and reliability. Both Babcock & Wilcox and Foster Wheeler are prepared to provide tube bundle designs for this effort.

DOE should also support operation of the large Wood-Ridge PFBC pilot facility it built in New Jersey. In order to ensure operation of this critical facility, Public Service Electric and Gas of New Jersey and Burns and Roe Incorporated have proposed a cost-shared project to DOE for a 21 month test program. The modification and operation of this $65 million facility is estimated at $20 to $30 million over the next three years with DOE funding of $12 million required.

A major facility gap is the lack of a 10 to 20 MW proof-of-concept capability to qualify a circulating fluid bed boiler design for PFBC application. Such a capability could be implemented, for example, in conjunction with the existing

Wood-Ridge facility to maximize common use of supporting facilities and instrumentation. The estimated capital cost of such a proof-of-concept combustion capability would be about $30 million. The advantage of the circulating PFBC would be to eliminate the potential for in-bed tube erosion and also to simplify coal feeding requirements.

Supporting PFBC research should also be expanded to combustor mechanics, hot gas cleanup, pollution control, and materials testing, plus application of non-intrusive diagnostic techniques to define critical performance parameters under the severe operating environment of PFBC. This should be co-funded at least $10 million per year over the next five years by DOE.

The ultimate goal of this R&D effort is the demonstration of a full scale PFBC module on a utility system. Such a demonstration, estimated to cost about $120 million, if the recommended supporting research and testing are implemented, is technically feasible this decade. The pacing item is the availability of Federal co-funding to match the already planned private sector initiative.

EPRI has been the primary US supporter of PFBC R&D outside of DOE. EPRI's primary objective has been to reduce the technical risks associated with PFBC through the turbocharged boiler approach so that its commercial advantages can be realized more rapidly. As indicated earlier, the turbocharged boiler advantages stem primarily from reduced gas turbine firing temperature. In addition, it lends itself to construction of shop assembled, barge transportable power generation modules which can be rapidly field erected.

EPRI's R&D efforts, in addition to turbocharged system design, control, and economics, have focused to date on development of a reliable gas filtration system and testing and qualification of combustor and turbine blade materials. Filter media have been qualified and testing of a large-scale, multi-element gas filtration module is planned. This latter effort is controlled, however, by the availability of Grimethorpe and/or similar facilities. EPRI funding for PFBC R&D, also paced by the limited DOE commitment, is only about $2 million per year. Accelerated participation in combustor development and testing is also planned, but is dependent on the availability of proof-of-concept facilities.

As indicated earlier, the government and industry of foreign countries are playing a significant part in the development of PFBC. Several proof-of-concept PFBC facilities are operating in Europe with ASEA-PFBC, Deutsche Babcock and Brown-Boveri providing primary technical and commercial leadership. As a result, commercial PFBC plants are now planned in Sweden, Germany and with American Electric Power (AEP), FP&L, PSE&G and Wisconsin Electric in the US, if Federal co-funding becomes available.

VI. CONCLUDING REMARKS

FBC offers a particularly attractive option for strategically resolving the various environmental issues which constrain the nation's growing dependence on coal while also improving the productivity and cost associated with its use. The nation is rapidly learning how to produce power from coal through FBC in a variety of forms meeting the demands of our diverse national energy system.

The question is whether we can advance this knowledge to practice in a period when both regulatory uncertainty and financial disincentives constrain the effort. The problem affects all phases of the development cycle but is greatest in the financially intensive large pilot and demonstration steps necessary for commercial confidence. A renewed Federal initiative, if jointly implemented with industry, will substantially enhance the nation's ability to commercialize the many developments in FBC technology.

The rate of commercialization and use of improved coal technology also depends on the development of regulatory and economic incentives which encourage introduction of innovative technology. Too often dependence on the adversarial approach to issue resolution makes the conflicts restricting coal use more severe and disruptive than necessary and restricts the introduction of technological improvement. This is particularly true in the environmental arena.

The coming decade will represent a major challenge to the utility industry in terms of staying abreast with even modest growth in electricity demand. For example, the 720,000 MW of peak generating capacity currently installed or under construction, is only sufficient to support about a 1.5% per year average growth rate in electricity demand between now and the end of the century. Each percent increase in demand growth rate would require about 100,000 MW of additional generating capability over the remainder of the century. This requirement is likely to be increased by other uncertainties including additional environmental legislation, further nuclear deferments, oil supply interruption and the, as yet, unproven ability to concurrently increase both the availability and life of existing capacity. A successful industry strategy to meet this challenge will require a balanced improvement in productivity from existing capacity, conservation and end use management, and additional generation capability.

On the supply side, fossil generating technology has not advanced appreciably over the past 30 years. Over this period emphasis has been instead on taking advantage of the economy of scale with average unit size increasing by about a factor of five. Although this was practical during the period of rapid electricity demand growth, these conditions are unlikely to apply again for most utilities in the foreseeable future. An effect of this essential freezing of fossil generating technology has been that the national average thermal efficiency of generation has steadily declined since it reached a maximum in the early 1960s. Also, even after adjusting for inflation, one MW of new fossil generating capacity today is about three times as expensive as in 1970. As a result, the economy of scale advantages gained earlier have been canceled out since 1970.

Based on these changing realities, the utility industry stands at a threshold of fundamental change in its technological base for power generation. The present commercial technology is nearly at the end of its development potential and is increasingly hard pressed to respond to the rapidly changing requirements being placed on the industry. New options such as FBC which can meet increasingly stringent siting and environmental demands and can be rapidly constructed in modular fashion over a range of unit sizes are particularly in demand. The next 10 years will therefore be of paramount importance, both in assuring future electricity supply and in controlling cost. Coping with this transition will require an intensive commitment over this period on the part of DOE, the utility industry, and its suppliers.

Historically the DOE program in fluidized bed combustion has been one of the most effective of the Federal energy R&D efforts. This is particularly true in the case of AFBC where the concerted Federal/private partnership has moved this technology from a technical curiosity to broad industrial application and to the threshold of large scale utility use. This integrated program has carefully and methodically moved AFBC technology through the development cycle from process development through engineering development to commercial demonstration and as such is a model for future joint technology development efforts.

AFBC has become an important boiler alternative because it is an evolutionary improvement in coal utilization, better meeting the requirements of the 1990s. The capabilities which excite this interest include: (a) less sensitivity to fuel quality, thus permitting users to operate more in a "buyers" fuel market; (b) ability to control SO_2 and NO_x within the combustion process; and (c) less cost sensitivity to unit size.

Although AFBC is proceeding favorably into commercial application, considerable opportunity for continued DOE support exists. Rather than concentrating on the investigation of advanced, proprietary AFBC concepts, this support should be redirected to resolution of the generic materials, fuel characterization and environmental control considerations which pace its application. In addition, special emphasis should be placed on the demonstration of circulating AFBC. This DOE participation is particularly important since AFBC is largely a user-driven technology. The large boiler manufacturers have historically viewed AFBC as an alternative to their conventional coal-fired boilers. As such, they have not considered AFBC as a means to increase their market share. R&D support has therefore been heavily dependent on the user, DOE, and specialty firms who view AFBC as an entrance to specific, but small portions of the boiler market. Only recently have the large, traditional US boiler suppliers taken on active roles in developing the technology. While this may have eliminated shortcutting the development cycle, which often results from premature commercialization, it nevertheless has constrained the R&D resources available.

PFBC represents a much more critical R&D situation. This technology offers the advantages of AFBC plus added potential for modular construction and higher efficiency. It can be used to replace retiring coal-fired steam units, in new plants, or for repowering existing oil- and gas-fired units. As a result of approximately a decade of federally funded research, PFBC technology has now reached the proof-of-concept stage of development where its advantages can be confirmed. Unfortunately, as this critical threshold is reached, DOE support has been essentially terminated, thus stalling PFBC's potential for commercial application in the US.

Past PFBC R&D concentrated on high efficiency, large base-load combined-cycle power plants. The technical barriers to this technology (primarily hot-gas cleaning, hot-gas ducting and gas turbine erosion, fouling, and corrosion) are being reduced, but confidence in commercially applying such PFBC plants still requires a major effort. By emphasizing the development of the PFBC turbocharged boiler, the technology can be commercialized on an accelerated schedule with reduced risk and can also be economically applied to utility plant uprating or repowering by the early 1990s. Uprating of existing power plants to raise total plant output by adding supplemental PFBC turbocharged boiler promises to be the lowest cost incremental capacity available in this period. By developing PFBC in this low-risk configuration and proving its feasibility in financially attractive repowering applications, sufficient confidence can be gained to increase the firing temperature in future plants to combined-cycle conditions. This evolutionary path can eventually lead to the 40%+ efficient, direct coal-fired, combined-cycle power plant.

A major joint DOE/private initiative should therefore be mounted which consists of four primary elements: (a) supporting research on fluidization, materials and sorbent performance; (b) proof-of-concept testing at the Grimethorpe and Curtis-Wright facilities; (c) proof-of-concept development for circulating PFBC; and (d) demonstration of a 100 MW PFBC repowering module.

RECOMMENDATION

There is no shortage of opportunities to improve efficiency, reliability and environmental performance of coal combustion. The successful achievement of this objective, however, requires a more constructive partnership between government and the private sector. This new partnership should begin with research, development and especially demonstration of promising technology options. It should also be characterized by a concerted national effort to better understand environmental risks and the most effective strategies for their control, and should include incentives for the development and use of improved technology for clean coal use rather than short range, parasitic controls which have an unnecessary impact on productivity and cost.

The following specific budgeting recommendations are made concerning DOE support for FBC.

The composite FY 1985 DOE budget request for FBC R&D is $22.5 million. It is recommended that additional funding be available for FBC technology development as discussed previously and summarized in Table 9. This will increase the DOE FBC budget to $62 million in 1985 and $308 million over the next five years. Priority should be placed on PFBC because of its relatively higher risk and the cost effective opportunity it provides, through prefabricated transportable modules, to satisfy the probable capacity gap facing the utility industry by 1995. At the same time, AFBC should be supported at a nominal level, particularly circulating designs, to provide a confident technical base. In the event additional resources are not made available, it is strongly recommended that all FBC funds be focused on operation of the existing PFBC proof-of-concept facilities, particularly Grimethorpe, as the key step in establishing the confidence necessary in scale-up to demonstration.

TABLE 9

ESTIMATE OF DOE FUNDING REQUIREMENTS
(DOLLARS IN MILLIONS)

A. AFBC	1986	1987	1988	1989	1990	TOTAL DOE	ADD'L PRIVATE CO-FUNDING (% of Total)	GRAND TOTAL
1. Resolve Hardware Issues o Solids Handling o Feed System o Recycle o Freeboard	5	5	2	2	0	14	50%	28
2. Optimization of Pollution Control	2	2	2	2	0	8	50%	16
3. Fuels and Sorbent Characterization	2	2	2	2	0	8	50%	16
4. TVA Demonstration Support	15					15	87%	115
5. Circulating AFB Demonstration Support		15	10	5	0	30	75%	120
6. Fluidization Research, Model Validation, Data Base Analysis	5	5	2	2	0	14	25	19
TOTAL	29	29	18	13	0	89	72	314

TABLE 9
(Continued)
ESTIMATE OF DOE FUNDING REQUIREMENTS
(DOLLARS IN MILLIONS)

B.	PFBC	1986	1987	1988	1989	1990	TOTAL DOE	ADD'L PRIVATE CO-FUNDING (% of Total)	GRAND TOTAL
1.	Grimethorpe Support	5	5				10	80%	50
	o Combustor Design & Control o Solids Feeding & Discharge								
2.	Wood-Ridge Operation	10	5	2	2	2	21	35%	32
	o Integrated Combustor/Turbine o Hot Gas Cleanup o Solids Feeding & Developing o Turbine Reliability								
3.	Circulating PFBC	10	10	5	2	2	29	25%	39
	o Proof-of-concept Facility								
4.	PFBC Repowering Demonstration Support		10	25	25	5	65	50%	130
5.	Supporting PFBC R&D	10	10	5	5	5	35	50%	70
	o Combustion Mechanisms o Hot Gas Cleanup o Sorbent Performance o Erosion & Corrosion o Fuels & Sorbent Charact. o Solids Feeding & Discharge								
6.	Plant Cycle Analysis and Design	5	2	2	2		11	50%	22
	TOTAL	40	42	39	36	14	171	50%	343

INFORMATION SOURCES

1. Chigier, N.A., Progress in Energy and Combustion - Science "Coal Combustion and Applications," Vol. 10 Number 2, pp. 106-115, Pergamon Press, New York, NY (1984).
2. Ehrlich, S., Keynote Address to the 3rd International Conference on Fluidized Bed Combustion, The Institute of Energy, London, England (1984).
3. Howard, J.R., Fluidized Bed - Combustion and Applications, Applied Science Publishers Ltd., London, England (1983).
4. Howe, W., et. al., Progress on AFBC Development for Electric Utility Application, 11th Energy Technology Conference, Washington, DC (1984).
5. Krishman, R.P., et. al., Oak Ridge National Laboratory, A Review of Fluidized Bed Combustion Technology in the United States, 16th International Center for Heat & Mass Transfer Symposium on Heat & Mass Transfer in Fixed and Fluidized Beds, Dubrovnik, Yugoslavia (September 1984).
6. Miller, S.A., et. al, Pressurized Fluidized-Bed Combustion Technology - Technical Evaluations, Argonne National Laboratory, ANL/FE-82-3, Argonne, IL (1981).
7. Atmospheric Fluidized Bed Summary Program Plan, US Department of Energy Office of Fossil Energy, Washington, DC (1984).
8. FY 1985 Congressional Budget Request, Fossil Energy Research and Development - Coal, Vol. 6, US Department of Energy, Washington, DC (1984).
9. Proceedings of the 3rd International Fluidized Conference, "Fluidized Combustion--Is it Achieving its Promise?," The Institute of Energy, London, England (1984).
10. Proceedings of the 7th International Conference on Fluidized Bed Combustion, DOE/METC/83-48, Philadelphia, PA (1982)
11. Proceedings of the Pressurized Fluidized Bed Combustion Workshop, US Department of Energy/Electric Power Research Institute, New Orleans, LA (1982).
12. Technical Assessment Guide, Electric Power Research Institute, EPRI P-2410-SR, Palo Alto, CA (1982).

D. AIRBLOWN GASIFIERS

by: William McCormick

I. INTRODUCTION

Gasification of coal as a means to achieve an ultimately clean combustion of this fuel represents one of the oldest chemical processing concepts; it was widely used during the 19th century industrial revolution. Gasification with air results in a BTU value of the gas in the 140-180 BTU/cb. ft. range, usually referred to as Lo-BTU gas. With the arrival of tonnage oxygen, emphasis has been almost exclusively on new gasifiers using this oxidant, particularly at elevated pressure, and these are now the essential centepiece of virtually every system used to convert coal to synthetic gases or liquids. Synthetics have become a major R&D goal in their own right and are specifically excluded from the present study.

This is not to say that gasification with oxygen under pressure cannot be considered for "clean use of coal". In fact, this configuration was and is being demonstrated in several power plants (Lunen, Coolwater, Plaquemines), broadly speaking, as a source of clean gas for use as fuel or for synthesis, etc.

II. DEFINITION

This study concerns itself with the use of airblown gasifiers as a means to "burn coal in two stages", including removal of the key polluting emissions from the raw gas. Accordingly, the R&D problems associated with this system can be conveniently considered as they relate to the four steps comprising the system:

1) Gasification
2) Gas clean up
3) Use of Lo-BTU gas.
4) Solid and aqueous wastes

1. Gasification With Air

In principle, all the gas/solid reactors used in gasification can be operatec with air, fixed bed, fluid bed, entrained solids, etc. However, in practice entrained solid reactors have been used only with oxygen. Historically, most airblown reactors have been of the fixed bed type, but fluid beds can also be run with air. Use of high air preheat may open the door to airblown entrained solid gasifiers and recent advances with high temperature gas-to-gas heat exchangers may be able to help, but no R&D program to this end is under consideration.

As to air gasification in fixed or fluid beds, it is not necessary here to recite the several commercial purveyors of such equipment. Generally the well-known advantages and disadvantages of either, which apply to oxygen blown operation, will also apply to operation with air. Thus the countercurrent fixed bed units are highly efficient, but impose constraints on capacity related to the size of the coal, its tendency to cake and to reactivity. The atmospheric fixed bed version has generally limited capacity subject to these three properties of the feed coal. Countercurrency will also inevitably cause tar to be evolved as the coal first reaches carbonization temperature (700 to 1,000°F). Several systems have been proposed and tested which minimize tar yield, or render it innocuous.

In the past, these fixed bed reactors have generally been used on specially selected coals (anthracite or coke of lump size) and a need exists to obtain valid operating data on other coals in order to broaden the potential market for this equipment. Standardized tests on a fixed bed reactor would be required to compare the major US coal types (bituminous, sub-bituminous, lignite and anthracite). For each, certain variables need to be systematically explored, including among others:

a) Coal feed size limit (% fines) for stable operation;

b) Coal feed size ratio (breadth of size range);

c) Effect of degradation on operation.

The information would be required to allow proper procurement of coal for industrial applications, where the market for Lo-BTU gas seems to be concentrated.

For fine coal sizes (which would have to be agglomerated to permit their use in fixed beds), the fluid bed reactor offers a good alternate, notably because it can also accommodate larger capacity. The Winkler gasifier remains the most demonstrated example, but its performance with air requires improvements, particularly in terms of carbon conversion. Carbon loss through withdrawal from the bed with the ash and through carryover with the product gas ranged from 20% to 40%. Thus, operation of fluid bed gasifiers under conditions favoring agglomeration (clinkering) of the ash is now being developed which would greatly reduce carbon loss in the ash. The system has yet to be tested on a commercial scale and DOE may consider support of the airblown, fluid bed, ash agglomerating gasifiers if adequate private sector co-funding is available.

An interesting new development in airblown gasification is the Kiln gas process currently being tested at a 600 ton per day scale. Completion of this project may also be included in the DOE program if DOE decides that it is warranted.

2. Gas Clean-Up

A special R&D opportunity exists in the area of clean-up (desulfurizing) of raw Lo-BTU gas. DOE is engaged in this area of gas clean-up, with major emphasis on control of alkalis and particulates for use on hot pressurized gas streams (supplying gas to gas turbine power units). In order to help introduction of Lo-BTU gas to a wider industrial market, the program would also need to give attention to the problem of H_2S removal from hot, atmospheric pressure gas streams in the range of 800° to 1,500°F, the exit temperatures of the various gasifiers.

This subject of gas clean-up, hopefully at low cost, is probably the most critical need before Lo-BTU gas can be expected to command a wider acceptance.

3. Use of Lo-BTU Gas

The low heating value of this fuel does not permit wide range distribution by pipeline grid; most installations will be tightly integrated with the final user, where the gas is burned.

This raises the question about combustion technology and particularly the potential problem of de-rating the capacity of the final user's equipment. This is obviously a very site specific matter. There may be no generic R&D program which addresses itself to all situations, but the potential of air-preheat for Lo-BTU combustion systems as a means to reduce de-rating, deserves study. This particularly is true since new alloys, etc. have recently been developed that permit use of higher preheat levels. Another indirect approach involves use of lower cost air separation techniques (membranes, etc.) to produce enriched air for these gasifiers.

4. Solid and Aqueous Wastes

The solid wastes, ash, and waste liquor from gasifiers present different disposal problems from those encountered with direct combustion of coal.

Ashes will tend to contain higher levels of residual carbon, and leaching must be tested to assure proper disposal. Obviously, the problem is coal- and gasifier-specific. Data related to this must be obtained to permit adoption of the system.

Finally, it is known that almost all gasifiers will in most cases generate waste waters which also need special attention. The only exception might be tar-free gasifiers followed by hot gas clean-up. Research will therefore be needed to define liquor treatment. Since Lo-BTU gas systems are likely to be fairly small, the preferred disposal may be by way of municipal systems, but some pretreatment may be required to allow this method of disposal.

III. RECOMMENDATION

Without definition of a detailed R&D program for the Lo-BTU gas development, it is estimated that up to $20 million per year would be required to cover all the key issues in a program extended over a 5 year period. Obviously, much of this money would come from the private sector, but some DOE involvement to serve as lead agency and to contribute seed money would be desirable to assure timely progress.

E. POST-COMBUSTION EMISSION CONTROL

by: Lawrence Papay

I. INTRODUCTION

Coal-fired boilers are required to comply with industry specific Federal and state regulations that limit the emissions of sulfur oxides, nitrogen oxides and particulate matter. Ambient air standards are also set for ozone, lead and carbon monoxide emissions. In a Federal attainment area, the EPA or the delegated agencies also make a case-by-case Best Available Control Technology (BACT) determination for asbestos, mercury, berylium, vinylchloride and other pollutants emitted above certain quantities. Specific technologies and measures used to comply with regulatory requirements are at the discretion of the plant operator as long as equivalent or superior performance can be demonstrated. In addition, regulatory agencies periodically review their regulations (some retroactively applied) to reflect technology development and new environmental concerns. For effective acid rain precursor control, pollutant reduction will be required for both new and existing power plants, and as such, there will be a large potential market for novel, economical, retrofittable control technologies for existing facilities.

II. DEFINITION OF SUBJECT

This section provides a summary of flue gas emission control systems and identifies recommended federal involvement in the research and development of these technologies. Pollution emission reduction from a coal-fired facility can be achieved by various means including coal processing, combustion modifications, and chemical additives in the combustion chamber as well as post-combustion flue gas treatment. This section only addresses technologies associated with flue gas treatment of sulfur oxides, nitrogen oxides and particulates.

It should, however, be recognized that flue gas desulfurization (FGD) systems will remain the most widely used environmental control concept for coal-fired units for near- and medium-term. It should receive proper attention for this reason alone. All other control options will have to be compared to FGD in terms of efficiency, cost, availability and reliability.

III. STATE OF THE ART

1. SO_2 Removal

Over 80% of the current 124 commercial utility FGD systems are wet lime/limestone throwaway process or variations of the basic system. The acidic sulfur oxides in the flue gas react with alkaline components of the slurry. The waste slurry is then dewatered to about 50% water and 50% insoluble material. The dewatered wastes are then either landfilled directly or treated further to enhance the physical properties of the waste prior to disposal. In the case of saleable product FGD systems, gypsum, elemental sulfur or sulfuric acid are produced.

Currently, there are six basic types of FGD systems in commercial operation: wet lime/limestone, spray dryer, dual alkali, sodium sulfite, magnesium oxide, and aqueous carbonate.

Despite its widespread use and a removal efficiency rate of over 90%, the wet lime/limestone process still encounters some design and operational uncertainties. The waste slurry is difficult to dewater and the resultant soluble sulfite makes disposal difficult in many areas.

The lime spray dryer system, a "throwaway" process, is gaining in popularity. Relative to the wet lime/limestone systems, this system has less corrosion problems, has simpler design and produces a dry solid waste. The lime in the slurry reacts with SO_2 to form calcium sulfite/sulfate. Most of the water in the slurry evaporates in the scrubber tower to form an essentially dry solid waste. The dry sulfite/sulfate is collected in the baghouse together with the flyash. Similar to the conventional FGD system, this process produces waste that contains water soluble sulfite. The system removal efficiency ranges between 60%-90%. Due to the high cost of reagents, its application is limited primarily to plants using low or medium sulfur coal. The capital and levelized busbar costs are similar to those of a conventional wet limestone FGD system. Most of the commercial systems are meeting or exceeding the manufacturer's SO_2 removal guarantees.

The "throwaway" dual alkali system involves a two step process. SO_2 in the flue gas first reacts with a sodium/potassium sulfite solution and the resultant sulfite/sulfate is regenerated by the addition of lime/limestone to form calcium sulfate/sulfite. The removal efficiency is approximately 90%. This system is best suited for high sulfur coal facilities.

Even though saleable product FGD processes can achieve 90% SO_2 removal and alleviate most of the waste disposal problems, they are more complex and expensive than the throwaway system. The Wellman-Lord process uses a sodium sulfite solution to remove SO_2 from the flue gas. The resultant bisulfite solution is treated in a steam evaporator to regenerate the sulfite solution while releasing a SO_2 rich gas stream which is then directed to a two step reduction system to form elemental sulfur. In addition to high energy usage, this process is sensitive to flue gas particles, HCl, and SO_3. Thus, a prescrubber is required. the MgO process uses magnesium oxide solution to remove SO_2 from the flue gas to produce a magnesium sulfite slurry. The slurry is then calcined (1800°F) producing SO_2 gas and reusable magnesium oxide. The SO_2 is then reduced to elemental sulfur or converted to sulfuric acid. In the aqueous carbonate process, a sodium carbonate solution is atomized in a spray dryer to form sodium sulfite/sulfate solid waste which is collected in the baghouse. In a three step process, the solid is then converted to elemental sulfur and the regenerated reagent.

The availability of the scrubbing system is a function of a number of variables, foremost being the type of system and type of service (i.e., base load, intermediate or peaking) as well as the number of scrubbing modules installed. For the year between March 1981 and March 1982, the availability of limestone slurry systems averaged 73%, lime slurry systems 84% and dual alkali systems 96%. The use of additives such as magnesium salts or organic acids appears to enhance availability of the lime/limestone systems.

Table 1 summarizes the status of FGD systems in the United States as of September 1984. Table 2 provides estimates of FGD capacity through the year 2020. These estimates assume a 2% per year growth rate beyond 1990 for new coal-fired capacity, and assume that old plant retirements are non-FGD coal technology applications are negligible.

2. NO_x Removal

Current federal regulations for NO_x emissions are being met by methods that are more cost-effective than other flue gas treatment. Full scale flue gas NO_x control systems are not in commercial use in any US coal-fired power plants.

The current practice for flue gas NO_x removal in Japan is by selective catalytic reduction (SCR), which provides a removal efficiency of 50% to 80%. Of the 93 SCR systems installed, 26 systems are on coal-fired units. Eight additional installations have been planned by 1990 in Japan. The Japanese technologies are being tested and demonstrated in the US on a commercial demonstration size (107.5 MW oil-fired unit) by the Southern California Edison Company and on selected small refinery boilers. The Exxon thermal $DeNO_x$ process (selective non-catalytic reduction - SNCR) has been tested in Japan and in the US by the Los Angeles Department of Water and Power.

Both the SCR and SNCR processes rely on the reduction of nitrogen oxides in the presence of ammonia to form nitrogen gas and water. Difficulties identified with these processes, such as maintaining the equimolar ratio of ammonia and NO_x, undesirable organic compound formation, corrosion problems associated with oxidation of SO_2 to SO_3, ammonia slippage and unknown catalytic life, necessitate additional research and demonstration.

3. Particulate Matter Removal

The current commercial practice for particulate matter removal is by electrostatic precipitation (ESP), fabric filter bag units (baghouses) and wet scrubbers. ESP units are installed either upstream (hot ESP) or downstream of the air preheater (cold ESP). Both arrangements electrostatically charge the flyash by passing it through high voltage chambers, and the charged particles are captured on collection plates. Most installed units are cold ESP. Better than 99% particulate matter removal can be achieved. Particulate matter removal in a baghouse is accomplished by passing the flue gas through fabric filter bags mounted above flyash collection hoppers. The flyash is collected in the bags and periodically removed by diverting the flue gas to a parallel bag collection chamber and back purging the flyash from the bags into the collection hoppers. A particulate matter removal rate of 99.9% can be achieved. Wet scrubber particulate matter removal is usually used in conjunction with SO_2 removal. Over 1400 ESP and 120 baghouse units are in operation or committed for utility power plants. The role of the baghouse will likely increase because of higher removal efficiency of fine particles (< 2 microns). On the other hand, ESP is applicable to low resistivity flyash.

TABLE 1

SUMMARY OF FGD PROCESS STATUS
(AS OF SEPTEMBER 1984; EPA/EPRI DATA)

	Operational		Under Construction		Contract Awarded		Total	
	No.	MW	No.	MW	No.	MW	No.	MW
THROWAWAY PRODUCT								
Wet								
Nonregenerable								
Limestone	57	24,012	12	7,566	8	5,530	77	37,108
Lime	36	14,852	3	2,132	1	650	40	17,634
Sodium Carbonate	6	1,505	--	---	2	1,100	8	2,605
Regenerable								
Dual Alkali	4	1,572	2	656	--	---	6	2,228
Dry (nonregenerable)								
Lime	7	1,840	6	2,913	4	1,910	17	6,663
Sodium Carbonate	1	440	1	550	--	---	2	990
SALEABLE PRODUCT								
Wet								
Nonregenerable								
Limestone	1	166	1	475	--	---	2	641
Lime	1	65	--	---	--	---	1	65
Regenerable								
Wellman-Lord	7	1,959	--	---	--	---	7	1,959
Magnasium Oxide	3	724	--	---	--	---	3	724
TOTAL THROWAWAY PRODUCT	111	44,221	24	13,817	15	9,190	150	67,228
TOTAL SALABLE PRODUCT	13	3,014	1	475	--	---	14	3,489
TOTAL WET	115	44,855	18	10,829	11	7,280	144	62,964
TOTAL DRY	9	2,380	7	3,463	4	1,910	20	7,753
TOTAL NONREGENERABLE	109	42,880	23	13,636	15	9,190	147	65,706
TOTAL REGENERABLE	15	4,355	2	656	--	---	17	5,011
TOTAL CONTROLLED CAPACITY	124	50,870	25	14,656	15	9,248	164	74,774
TOTAL SCRUBBED CAPACITY	124	47,255	25	14,335	15	9,190	164	70,780

TABLE 2

FORECASTS OF SCRUBBER COAL-FIRED CAPACITY
AT UTILITY POWER PLANTS IN THE US
(EPA Data)

	1980	1990	2000	2010	2020
Total Coal Generating Capacity (Gigawatts)	253	338	412	502	612
Scrubbed Capacity (Gigawatts)	31	104	178	268	378
Percent of Total, Scrubbed	12	31	43	53	62

Cost information related to the above discussed state of the art flue gas cleanup technologies is presented in Table 3.

IV. OUTLOOK FOR REQUIREMENTS FOR 2020

The regulatory requirements for SO_x, NO_x and particulate matter emissions will likely be tightened from current levels, especially in non-attainment areas. This, together with the anticipated significant increase in coal generating capacity by the year 2020 (see Table 2), will require improvement of existing technologies or development of new technology options to reduce cost, increase efficiency and reliability.

The technologies that would be adopted depend on progress in the development of new processes or improvement of existing technologies. Unless significant improvement can be made to the ESP, the baghouse will continue to be the predominant system for particulate matter control in near-term new installations. In the near future, a dry FGD scrubber with a baghouse will likely be the technology of choice for post combustion SO_2 control for low/medium sulfur coal-fired facilities. For plants using high sulfur coal, wet lime/limestone systems with some variation will continue to be used. If combustion modification is not sufficient to achieve desired NO_x reduction, selective catalytic/non-catalytic reduction systems will be available for post combustion control. One of the new combined NO_x/SO_x systems will probably become the system of choice for the year 1992 and beyond. The removal efficiency of these control systems for new plants will probably be greater in most cases than for those already in operation.

V. CURRENT R&D

Technologies currently being developed can be applied to new plants as well as existing facilities. The following discussion covers processes that are easily retrofittable to existing facilities. Other emerging technologies, while being developed mainly for new plants, can also be applicable to existing facilities if the space and economic constraints can be overcome.

TABLE 3

ESTIMATED COST OF STATE OF THE ART FLUE GAS CLEANUP TECHNOLOGIES
(1982 Dollars)

	NEW FACILITY		RETROFIT	
	$/kW	Levelized Mills/kWh	$/kW	Levelized Mills/kWh
SO_2				
Conventional Lime/ Limestone (L, H)	110-175	8-18	175-317	17-23
Spray Dryer (L)	110	7.5	148-252	10-18
Dual Alkali (H)	150-160	17	157-272	15-22
Wellman-Lord (H)	275	26	252-492	22-32
MgO (H)	270	19	340-378	21-27
Aqueous Carbonate (H)	400	31	500-560	34-43
PARTICULATE MATTER				
ESP	60	3.3	75-84	3.6-4.6
Baghouse	54	3.0	67-76	3.3-4.2

L = For Low Sulfur Coal Facility Only

H = For High Sulfur Coal Facility Only

L,H = For Both Low and High Sulfur Coal

Source: 1. Draft EPRI Report: "SO_2 and NO_x Retrofit Control Technologies Handbook"

2. "The Economics of Fibric Filters and Electrostatic Precipitators", 1983, R.R. Mora, R. Carr, and P. Goldbrunner.

Table 4 shows the estimated capital and levelized costs for emerging technologies that have been or are being demonstrated on a significant scale. These technologies will be commercially available prior to 1992 if developmental efforts are actively pursued. Similarly, Table 5 shows the estimated costs for new technologies that are still in bench or pilot scale testing. Due to uncertainties in this early development stage, commercialization prospects for these technologies remain unknown, but could in no case occur sooner than 1992. Thus, costs presented are highly speculative and should be used for comparative purposes only.

1. Technologies for Existing Plants

Numerous activities are being conducted to refine existing operating emission control systems. While these research activities are being performed by both the private and public sectors, continued government presence is necessary for smooth technology transfer. For particulate matter control, the research efforts are centered on performance improvement and optimization. Due to concerns related to trace element and inhalable particulate matter emissions, substantial emphasis is being placed on the removal of submicron sized particles. Examples of these research efforts include electrostatic, electromagnetic and sonic horn augmentation for fabric filtration; two stage ESP; and use of additives. Economically, the most attractive improvement for existing wet FGD systems is the use of organic (e.g., adipic) acids or magnesium salts to enhance SO_2 removal efficiency and reagent utilization. Results indicate that a removal efficiency of 95% can be achieved at reduced operating cost.

The large fresh water consumption (up to 5 gallons per minute per MW capacity) and the voluminous waste water discharge of a conventional wet FGD system may impose siting and operational problems for coal power plants, especially in the arid southwest. In this respect, reduced water consumption also lowers water treatment and disposal costs. The private sector, in conjunction with EPRI, is conducting research to reduce FGD water consumption, including recycling and biofouling control as well as integrated water systems for power plants. Other than indirect participation and information dissemination, no direct DOE involvement is needed at this time.

For effective acid rain precursor control, there is a need for novel, low-cost, low removal efficiency and retrofittable control technologies for the numerous existing coal-fired facilities that do not have all the desirable environmental control systems. Compared to high removal efficiency and higher cost systems, the trade-off is centered on lower removal efficiency for lower capital expenditures for facilities that have limited remaining useful lives and are not likely to be operated continuously. The large number of these facilities (hence the large market) together with large cumulative environmental improvements deserve additional national developmental efforts.

TABLE 4

ESTIMATED COSTS OF NEAR-TERM DEVELOPING CONTROL TECHNOLOGIES

(1982 DOLLARS)

	NEW FACILITY		RETROFIT	
	$/kW	Levelized Mills/kWh	$/kW	Levelized Mills/kWh
SO_2				
Chemical Addition (Organic Acid)			Negligible+	
Dry Injection (L)	90	7-20	110-125	8-20
CT-121 (H)	140	14	170-290	14-18
Saarberg-Holter (H)	130	16	163-182	18-22
DOWA (H)	175	14	219-245	15-20
NO_x				
SCR*	54-89	6-14	70-124	6-19
SNRC*	11	1.5	11-17	2-3

L = For Low Sulfur Coal Application

H = For High Sulfur Coal Application

* = Based on Japanese Experience; not in commercial use in US.

+ = Applicable to existing lime/limestone FGD systems only.

SOURCE: Draft EPRI Report, "SO_2 and NO_x Retrofit Control Technologies Handbook".

TABLE 5

ESTIMATED COST OF LONG-TERM DEVELOPING TECHNOLOGIES

(1982 DOLLARS)

	NEW INSTALLATIONS	
	$/kW	Levelized Mills/kWh
SO_2		
Flakt Boliden	390	30
CONOSOX	430	45
COMBINED NO_x and SO_x		
SULF-X	290	20
Copper Oxide	238	22
Carbon Absorption	117	23
Electron Beam	333	33
NOXSO	NA	NA

SOURCES:
1. Personal communications with EPRI, EPA and DOE. Since these technologies will not be commercially available until the late 1990s, the estimated costs shown are highly uncertain and depend on the success of technology development and breakthroughs.
2. Draft EPRI Report, "SO_2 and NO_x Retrofit Control Technologies Handbook".
3. "Current Status of Dry NO_x - SO_x Emission Control Process", S.M. Dalton, EPRI CS-3182, Vol. 1.
4. "Economic Evaluation of FGD Systems", EPRI CS-3342.

In most of the retrofit applications, major limitations include space requirements, extensive and costly modifications to the existing facility, capital cost requirements, loss of operating flexibility and potential output derating. A promising low cost FGD option is the dry injection of sorbent in the flue gas before the baghouse. This process has been demonstrated by EPRI in a full-scale facility and is applicable to both new or exiting low-sulfur coal-fired facilities. Additional research is needed for high sulfur coal applications, for use in conjunction with ESPs, for improved waste fixation and disposal, and for system optimization as well as for use with lower cost alternate reagents. Based on the success of this process development, the Public Service Company of Colorado has recently announced the use of dry injection system for its new 500 MW coal-fired unit.

2. Technologies for New Facilities

Advanced limestone/gypsum FGD processes (Chiyoda Thoroughbred 121 [CT-121] and Saarberg-Holter) are commercially available in foreign countries, but have not been fully demonstrated in the US. These systems have high probabilities for commercial readiness in the US by the end of this decade as alternatives to conventional wet scrubbers. These processes produce marketable gypsum by forced oxidization of the spent slurry. The Saarberg-Holter system has been demonstrated in Europe in full-scale coal-fired power plants while the CT-121 system was successfully tested by EPRI in a 23 MW prototype. While achieving an SO_2 removal efficiency of 90% at a lower levelized cost, these processes also make more complete use of reagents and eliminate plugging and scaling.

A modified dual alkali system, using aluminum sulfate instead of caustic soda as the scrubbing reagent is being developed. The spent reagent from this process (DOWA) is oxidized and regenerated with lime or limestone to form gypsum. The DOWA process, commercially available in Japan, makes more efficient use of limestone, has better load following capability and promises lower cost. A disadvantage is that the soluble aluminum sulfate contained in the solid waste may pose a problem for disposal or for sale. The DOWA process was tested by EPRI at a 10 MW pilot plant and achieved a 90% removal rate.

Of the post-combustion cleanup technologies for nitrogen oxides control, the selective catalytic and selective non-catalytic reduction systems are the most advanced. Pilot scale systems of these two technologies have been tested on flue gas from coal-fired power plants. They were found to be effective for the cases tested. However, these processes are more expensive than combustion modification. Demonstration-scale tests for US coal-fired power plants have not yet been conducted. The selective catalytic reduction (SCR) process converts nitrogen oxides to elemental nitrogen in the presence of gaseous ammonia at 700°F and is capable of achieving 80%-90% removal of NO_x. The use of this system for coal-fired plants is limited only to pilot-scale studies. The selective non-catalytic reduction (SNCR) process removes nitrogen at elevated temperatures of 1700-2200°F in the presence of ammonia. Testing of this process has been limited to pilot-scale coal-fired facilities, and it has been found less effective (60% removal rate vs. 90% for SCR). Additional research work is required for both the SCR and SNCR processes. Major improvements are needed in the process control subsystem, extension of catalyst life, cost reduction, and elimination of ammonia slippage.
Almost all of the long-term research efforts are focused on advanced SO_2 control

technologies or combined SO_2/NO_x and particle removal. For advanced SO_2 control technologies, the primary emphasis is placed on reagent regeneration and saleable product processes. Although these processes are usually more complex to control and operate, they will eliminate or minimize the solid waste disposal problems. The Flakt Boliden (sodium citrate reagent) and CONOSOX (potassium salt reagent) processes are in pilot-scale development with projected commercial availability for the late 1990s. Due to their high costs, these two technologies will have difficulties in gaining commercial acceptance unless major cost reductions and/or breakthroughs can be found.

There are numerous developing technologies that may have the capability of simultaneous removal of NO_x and SO_x. These technologies, sponsored primarily by DOE, use more complex chemical processes not commonly used in the utility industry. Bench scale/pilot tests were conducted for the copper oxide, carbon absorption, electron beam, NOXSO and SULF-X processes. Other processes that exhibit some degree of removal efficiency include glow discharge, zinc and zeolite catalyst. However, these processes are not expected to be commercially available prior to 1992, with the majority available after the year 2000.

In a copper oxide reduction system, a fixed-bed or a fluidized-bed of copper oxide is used to absorb the flue gas SO_2 and form copper sulfate. The copper sulfate is then further processed to form elemental copper and elemental sulfur in a two-stage process. The fixed-bed process has been used in a Japanese refinery since 1973, achieving 90% SO_2 and 40% NO_x removal. An EPA/DOE jointly-sponsored pilot-scale test on a coal-fired boiler at Tampa Electric Company achieved a removal efficiency of 90% for SO_2 and 70% for NO_x. The fluidized-bed process is being tested on a pilot scale by DOE at the Pittsburgh Energy Technology Center. Preliminary results from Japanese large-scale testing facilities indicate that it can achieve over 90% SO_2 and 70% NO_x removal.

Activated carbon can be used as a catalyst in reducing NO_x to N_2 in the presence of ammonia while acting as an absorbent for SO_2. The carbon is regenerated by heating to release the SO_2, which is then converted to elemental sulfur in a two-stage process. Pilot-scale tests achieved a removal efficiency of 70% for both SO_2 and NO_x.

The electron beam irradiation process, being actively pursued by DOE, involves the use of high energy electronic guns to dissociate the flue gas to form free radicals with an anticipated removal efficiency of 90% for SO_2 and 80% for NO_x. In the Avco-Ebara process, flue gas is humidified and cooled to about $200^{o}F$ and electron beams are used to ionize the gas to form ammonium nitrate and ammonium sulfate in the presence of ammonia. Under the sponsorship of DOE, this process is being tested on pilot scale at an Indianapolis power plant. In the Research-Cottrell process, a lime spray dryer is used for partial upstream removal of SO_2 while the remaining SO_2 and NO_x are captured in the electron beam reaction chamber. DOE is testing this process on a pilot scale at the TVA Shawnee Plant. However, the cost of the electron beam gun must be reduced drastically for commercial viability of both systems.

The NOXSO process is a dry regenerative process using granular sodium oxide on aluminum in a moving bed reactor to remove SO_x and NO_x at $250\text{-}400^{o}F$. The spent reagent is regenerated at elevated temperatures in the presence of H_2S to form elemental sulfur and nitrogen. This process is being tested by DOE on a bench scale at the TVA Shawnee plant and has achieved a simultaneous removal efficiency of 90% for both SO_2 and NO_x.

The SULF-X process uses an iron sulfide slurry solution for combined NO_x/SO_x capture. This process is being tested by the State of Pennsylvania on a pilot scale at the Western Hospital Center in Canonsburg, Pennsylvania, achieving 90% SO_2 and 70% NO_x removal. Efforts are underway to increase the NO_x removal rate to 90%.

VI. COMMENT TO R&D PROGRAM

The DOE flue gas cleanup program is focused on the development of advanced technologies with long-term commercialization schedules. DOE intends to develop high risk, high payoff new technologies through the proof-of-concept stage, leaving the demonstration, optimization and commercialization activities for the private sector. It should be noted that it takes at least five years after the proof-of-concept stage to demonstrate a new technology on a full scale prior to its first commercial application. Thus, if the combined NO_x/SO_2 cleanup technology options were to be developed by October 1990 as scheduled, they would not be commercially available until 1995. The drastic termination of governmental support after the proof-of-concept stage increases the difficulties for the private sector to proceed with the demonstration and commercialization phases. Uncertainties and risks associated with such large demonstration projects are often beyond the financial capability of one utility or supplier. Continued federal presence during the demonstration and early commercialization phases will be necessary for effective and timely technology transfer. While it is highly desirable for the private sector to take the lead and have project management responsibility in a demonstration project, it is a proper role for the government to provide financial and technical support and timely information dissemination during the transition period.

For effective acid rain precursor control, there is an urgent need for low-cost, low-efficiency control technologies for existing coal-fired facilities. The current DOE schedule of September 1987 for the completion of acid rain control technology (ARCT) development should be accelerated to meet this need. By eliminating some of the paper studies, this program can be accelerated by one year. In addition, DOE must carry out these ARCTs beyond the proof-of-concept stage by direct funding and participation in full-scale testing in conjunction with EPA, EPRI and the private sector. Failure to participate in this carry-through effort will delay the commercialization of these emerging ARCTs.

The EPA program concentrates on near-term commercialization of lower cost variations of base technologies that already have commercial track records. The EPA program goal is to ensure that best available control technology (BACT) is available to meet the mandated environmental standards. In this respect, increased interagency coordination and cooperation in the improvement and development of spray dryer and dry injection technologies will be beneficial. For retrofit application of dry FGD, DOE must take a lead role in improving the performance of existing and new ESPs to handle varying ash loading and ash alkalinity.

The private sector work is primarily directed at near-term technologies to improve the cost, reliability and operation of existing control systems. As such, its program is directed at solving immediate problems, removing an objectionable emittant, controlling and disposing of waste products, reducing costs and optimizing system operation.

While there is good interaction among parties involved in flue gas cleanup technologies, such coordination should be increased to ensure effective execution of the DOE program plan. In particular, the private sector, which will be the ultimate user of the developing technologies, can assist DOE in the selection of processes to pursue, in early identification of scale-up and operational problems, and retrofit practicality.

VII. CONCLUDING COMMENTS

The overall DOE program is comprehensive and generally well conceived. However, it is deficient in two areas. First, technologies that reduce SO_2 and NO_x emission from existing plants are not adequately covered. Secondly, technologies being evaluated for long-term applications are so dispersed that procedures should be established (with active industry participation and interagency coordination) to better focus research efforts on the most promising processes.

To address the acid rain problem, more emphasis must be placed on the development of low-cost, low-efficiency retrofittable control technologies. Such technologies must be close to commercial readiness or at full-scale testing, be cost effective, and have broad applications.

For existing facilities with FGD and/or particulate matter control systems, every effort should be made to promote the use of additives to enhance system performance. More full-scale testing should be conducted to demonstrate cost savings and removal efficiency improvements. Although EPA has made some efforts in this area, DOE should increase its participation in the overall program to accelerate commercialization of these promising concepts.

For existing facilities with particulate matter control but no FGD systems, the current research efforts in spray dryer and dry injection should be strengthened to accelerate their commercialization. The use of existing ESPs for spray dryer/dry injection should be further pursued. Alternative reagents for the dry FGD systems should be developed to minimize the costs, especially for high sulfur coal applications.

For NO_x control of existing facilities, combustion modification appears to be the least cost option. SCR and SNCR are the most likely near-term post combustion control processes if the catalyst life and the process control subsystem can be improved. Full-scale demonstration would be the next stage of development. Since these technologies are expensive, they should be pursued only after funding for the above mentioned research needs in combustion control and SO_2 removal processes are satisfied.

To increase technology options for new plants to be constructed before 1992, continued effort to develop advanced limestone/gypsum FGD processes (in particular the CT-121 process) may be warranted for cost saving purposes. For new plants that come on-line after 1992, numerous new potential processes may become available. However, there is not enough information to select superior technology(ies) at this time. The emphasis by DOE on a combined SO_2/NO_x particulate matter control system that minimizes solid waste production appears to be well placed. These new technologies have potential removal efficiencies of 90% for NO_x and SO_2 and over 99% for particulate matter. Nevertheless, the cost of these new technologies does not appear to be significantly lower than those of existing systems. As indicated in Table 6, the new developing combined removal technologies offer only minor economic advantage for plants using low sulfur coal. For high sulfur coal, the advantage is more significant. The pursuit of electron beam technology is viable only if the cost can be significantly reduced.

TABLE 6

LEVELIZED COSTS FOR FLUE GAS CLEANUP SYSTEMS
(1982 DOLLARS; DOE/ERA/EPRI DATA)

PROCESSES	Low Sulfur Coal Levelized Cost Mills/kWh	High Sulfur Coal Levelized Cost Mills/kWh
SO_2 Control		
A. Conventional Limestone	8	18
B. Lime Spray Dryer	8	
C. Nacholite Injection	10	
D. Trona Injection	9	
E. CT-121		14
F. DOWA		14
G. Saarbert-Holter		16
H. Limestone Dual ALkali		16
I. Lime Dual Alkali		17
J. Wet Lime		20
K. Wellman-Lord		26
L. MgO		19
M. Flakt Boliden		30
N. Aqueous Carbonate		31
O. CONOSOX		45
NO_x Control		
SCR	10	
SNCR	2	
Particulate Matter		
ESP	3	
Baghouse	3	
Combined NO_x/SO_2 Systems		
Copper Oxides		22
Carbon Absorption		23
Electron Beam		33
NOXSO		NA
SULF-X		20

VIII. RECOMMENDATION

The past de-emphasis on flue gas cleanup technology development (other than combined systems) has placed DOE in a catch-up situation. DOE's acid rain control technology (ARCT) program should be accelerated. The experience of other entities such as EPA, TVA, national laboratories, EPRI and the private sector should be solicited and field tests should be conducted as soon as possible. In addition, DOE's ARCT program should go beyond the "proof-of-concept" stage. Instead of initiating new processes or totally separate efforts, DOE should explore joint programs with other agencies and the private sector.

DOE's long range program appears viable. However, the extensive emphasis on electron beam technology should be reconsidered unless significant cost reductions and technical breakthroughs are anticipated. The current federal program on pollution control technology development is spread among different federal agencies with overlapping responsibilities and missions. Unless the agencies work closely together in coordinating their activities, certain needs may not be fulfilled.

The highest priority in emission control technology development and demonstration must be placed on those emerging systems that are capable of meeting the immediate need of the private sector while simultaneously meeting the national goal of acid rain precursor control. The following composite ranking of action items reflects the needs of the private sector, and as such, should be pursued as part of the national effort, under the direction of Federal Government* programmatic funding requirements to meet these needs are detailed in Table 7.

NEAR TERM NEEDS (commercially available prior to 1992)

o Acid rain control technology (ARCT) development and demonstration:

  - dry FGD systems, especially for use with existing ESPs and for high sulfur coal applications;
  - performance improvements and operation and maintenance cost reductions for existing control systems;
  - use of low cost additives for existing systems.

o Develop and demonstrate low cost control technologies for use in conjunction with conversion of existing oil/gas units to coal.

o Full-scale demonstration of SCR on a coal-fired boiler.

o Full-scale demonstration of the CT-121 process.

---

*In addition to flue gas cleanup, other emerging clean coal technologies that should be pursued include: direct coal-water slurry firing, slagging combustor, in-burner SO_2 and NO_x control, LIMB, coal cleaning, and atmospheric and pressurized fluidized bed combustion, as well as coal gasification and liquefaction.

LONG TERM NEEDS (commercially available after 1992)

- o Second generation dry FGD systems.
- o Combined SO_2/NO_x particulate matter control technologies.

The composite FY 1985 DOE budget request is $14 million for flue gas cleanup technologies. The current EPRI program plan anticipates an expenditure of $96 million for flue gas cleanup for the years 1985 through 1989. Should additional funds be available for clean coal technology development, such funds should be directed to the sponsoring of demonstration projects to meet both the near-term and long-term needs. Cost estimates (Table 7) for the above necessary programs are highly uncertain at this time, and can only be made more definite upon the selection of demonstration sites.

TABLE 7

ESTIMATED FUNDING REQUIREMENTS*

Action Items	1986	1987	1988	1989	1990	TOTAL
Near Term Needs						
Acid Rain Control Technology	36	18	18	14		86
Control Technology for Fuel Conversion Facilities	4	8	15	8	8	43
Full Scale SCR	10	23	6	6	6	51
Full Scale CT-121	4	20	20	7	7	58
Long Term Needs						
Second Gen. Dry FGD	4	6	15	20	15	60
Combined Systems	7	15	60	100	80	262
TOTAL	65	90	134	155	116	560

---

*Total estimated expenditure; highly site specific; percentage of private and public contributions to each action item is unknown at this time.

WASTE MANAGEMENT

by: Edward Rubin

1. DEFINITION OF SUBJECT

Coal utilization inevitably is accompanied by the production of solid wastes. At coal-fired power plants, the principal waste materials traditionally have been boiler bottom ash plus fly ash collected from the flue gas stream. This represents a considerable quantity of material (roughly 80 million tons per year) since ash typically accounts for 10% to 20% of the total mass of coal burned. In addition, power plants produce a number of "low volume" wastes from auxiliary apparatus such as water demineralizers.

New environmental regulations enacted in the 1970s have resulted in the generation of significant additional quantities of solid waste at coal-fired power plants. Flue gas desulfurization (FGD) systems installed to comply with sulfur dioxide air pollution regulations (now required on all new coal-fired power plants) typically produce a calcium-based sludge in quantities that may be up to 2 or 3 times greater than the amount of ash material generated by a particular plant. New water pollution regulations which prohibit or stringently limit thermal and chemical discharges to waterways also have resulted in the installation of control technologies which invariably produce some quantity of solid waste, typically in the form of a wet sludge. While these quantities are small compared to fly ash and FGD wastes, their chemical composition also must be carefully considered in the current regulatory environment.

Coal preparation plants represent the other major source of coal utilization wastes (aside from the mining process itself, which is not considered in this report). Preparation plant refuse may contain 5% to 20% of the original coal mass, depending on the level of cleaning. These wastes consist primarily of coal ash as well as some sulfur-bearing pyrite and coal unavoidably collected with the refuse material. This waste leaves the coal preparation plant as a slurry, which may undergo some degree of dewatering prior to disposal.

Federal legislation in recent years, particularly the Resource Conservation and Recovery Act (RCRA), the Solid Waste Disposal Act (SWDA) and the Toxic Substances Control Act (TSCA), has focused special attention on problems of solid waste disposal. The principal concern is over the release of potentially hazardous or toxic chemical compounds and elements (such as heavy metals) into surface or groundwater systems as a result of direct runoff or chemical leaching through soils. To a large extent, the focus of this concern has been on wastes from various chemical processes as opposed to those from coal combustion or processing. Nonetheless, as air and water pollution regulations have prohibited or minimized the release of coal-related pollutants to the water and air, their presence in the form of solid waste has grown in significance.

As with other environmental media, responsibility for the development and promulgation of regulations governing the disposal of solid and liquid waste lies with the U.S. Environmental Protection Agency (EPA), and with state or local government agencies. At the federal level, the designation of wastes under RCRA as either "hazardous" or "non-hazardous" is perhaps the most critical factor affecting coal utilization processes. At the present time, EPA regulations treat high volume coal combustion wastes from electric utilities as a special category not considered to be "hazardous" (as determined by specified test procedures). A final designation, however, is still pending at EPA. In addition, specific waste disposal requirements vary from state to state. Thus, over the long term there still remains considerable uncertainty regarding the future development of solid waste regulations, and their impact on the viability and cost of both conventional coal utilization technology and advanced technologies currently in the research and development stage. The important message is that the "clean use of coal" does not simply refer to the solution of air pollution problems. Liquid and solid waste management also must be an integral part of any R&D program aimed at the clean use of coal.

II. STATE OF THE ART

Current solid waste disposal practices at power plants are highly variable, and depend in part on whether or not the plant is equipped with an FGD system. Older plants not required to have FGD generally dispose of their ash by transporting it in a moist state to an ash disposal pond. To comply with water pollution regulations, the supernatent liquid may be treated prior to discharge. For plants with FGD systems, current waste disposal practice typically involves mixing FGD sludge and fly ash (possibly with the addition of a fixing agent) and co-disposal in a pond or dry landfill. Landfill operations are emerging as the generally preferred disposal alternative for new power plants, though the choice of disposal method often is highly site-specific. Depending on the requirements of state and local authorities, solid waste disposal ponds also may be required to have synthetic liners to prevent the leaching of materials into the ground. Waste disposal sites more frequently have been constructed using layers of natural clay to provide a nominally impermeable barrier to leachates. In similar fashion, waste disposal practices at modern coal preparation plants typically involve the sanitary landfill of dewatered coal refuse material. Older plants, however, simply left ponds or coal refuse piles that are subject to spontaneous combustion as well as to leaching and runoff into surface waters.

An alternative to the disposal of waste materials is their utilization as a commercial by-product. Potential applications of conventional power plant waste include use for structural fill, lightweight aggregate, cement manufacturing, soil stabilization, concrete products, and liming agents. FGD processes also can be designed to produce by-product sulfur, sulfuric acid, or commercial grade gypsum. Wastes from coal cleaning plants are a potential source of low-grade fuel (e.g., for fluidized bed boilers).

While the utilization of power plant ash and FGD wastes is relatively widespread in parts of Europe and Japan, such applications are much less common in the U.S. because of differences in commercial markets and the greater availability of land for waste disposal. The use of fly ash as fill material for road construction and as a lightweight aggregate for cement are the principal utilization markets for power plant wastes at the present time. However, this represents only a small portion of total waste production. While a few U.S. power plants use regenerative FGD systems producing salable by-products, such systems have not gained widespread use in this country because of their generally unfavorable economics. This is why U.S. plants typically dispose of the low-grade gypsum produced by conventional lime/limestone FGD systems rather than produce higher quality gypsum potentially suitable for wallboard and other applications (as is common practice in Germany and Japan). Thus, while state-of-the-art technology is capable of reducing solid waste generation by producing potentially usable by-products, this remains an economically unattractive option relative to waste disposal at the present time.

III. OUTLOOK FOR REQUIREMENTS FOR 2020

In general, the quantity of solid waste generated from coal utilization over the next several decades can be expected to grow significantly as FGD systems producing a wet or dry solid waste add to the traditional burden of mineral matter (bottom and fly ash). As discussed below, many emerging technologies and advanced coal utilization systems also generate larger quantities of solid waste than conventional power plants, potentially exacerbating future problems. Thus, the importance of solid waste as the ultimate disposal medium for coal-borne contaminants is likely to increase in future years. Future developments in the economic utilization of these materials may offer one avenue for offsetting this growth in volume and potential adverse impacts.

IV. CURRENT R&D

The DOE Office of Fossil Energy (DOE/FE) maintains a Waste Management Program with a current annual R&D budget of approximately $2 million. The following paragraphs describe the DOE program objectives, current activities, and future plans. Other federal and private R&D programs are then briefly reviewed.

The DOE Program

The DOE Waste Management Program has five stated objectives:

- Advance the fundamental understanding of fossil fuel cycle waste characteristics to define the required R&D for effective management of the waste;

- Conduct the necessary R&D to develop sound technological and economic solutions for waste management in compliance with environmental constraints and institutional criteria;

- Conduct technical and economic assessments to select the waste management concepts that not only meet the environmental constraints and institutional criteria but also are the least disruptive to the economy, and to determine the market penetration potential of the technology;

- Establish the technology and related economic data base necessary for private sector assessment of the commercial viability of techniques and/or processes for management (disposal) of fossil fuel cycle wastes, e.g., coal preparation, flue gas cleanup, gas stream cleanup, and emerging technology process waste by-products;

- In addition to publication of reports, conduct, support, participate and co-sponsor waste management symposia, conferences, and workshops, as necessary, to provide a continuous exchange of information for technology transfer.

The recent emphasis of the the DOE waste management program has been on the characterization of wastes from conventional electric utility plants. There has been little work on the development of new disposal methods or control technology per se, this being viewed as a longer-term objective of the program that would be developed in response to any identified needs. Projects dealing with waste recovery, re-use or utilization have been phased out of the DOE program during the past two years.

Two studies initiated in the late 1970s represent recent major efforts of the Waste Management Program. One is a study of utility waste characteristics, completed in 1984. It characterized some 94 samples of coal feedstock, ash, and FGD sludge for coal combustion systems at 18 U.S. power plant sites, with a focus on trace metals and their leachability. Several samples characterized wastes from emerging energy technologies at six DOE-sponsored projects (e.g., the H-Coal process, oil shale, tar sands, etc.). New work is now underway to characterize organic compounds for these same samples. A more limited data base is available for coal preparation plant wastes, obtained from other projects supported under the waste management program.

A second major effort, initiated nearly six years ago, is a study of alternative waste disposal methods and costs as they relate to fossil fuel utilization. This addresses the range of potential impacts that could result from the implementation of regulations under RCRA and related legislation. It looks at three principal scenarios: the world before RCRA; the world after RCRA assuming utility wastes are designated as non-hazardous; and the world after RCRA assuming that wastes are designated as hazardous. The latter scenario includes two cases representing minimum and maximum cost. This effort has involved case studies of some 26 power plants, with the results used to project impacts for nearly 400 plants nationwide. Completion of this study is expected in 1985.

Having recently brought to completion a number of projects dealing primarily with the sampling and characterization of wastes from conventional coal utilization processes, the current focus of the Waste Management Program is on the characterization of wastes from emerging coal utilization technologies. DOE lists a comprehensive set of waste streams to be studied:

- Coal preparation wastes (physical and chemical processes)
- Conventional coal combustion wastes
- Flue gas cleanup wastes
- Gas stream cleanup wastes
- AFBC and PFBC wastes
- Oil shale residues
- Coal conversion process wastes
- Synfuel process waste by-products
- Wastes from advanced coal utilization technologies, i.e., MHD, fuel cell.

Details of this program are still being formulated, though it is envisioned to have three principal elements: acquisition of waste samples from emerging energy facilities; laboratory characterization studies focused on trace metals and organic compounds; and field studies to determine the actual fate of wastes and leachates in the environment. In general, the technologies selected for these studies will be prioritized according to their state of development, with initial efforts expected to focus on coal gasification plants and atmospheric fluidized bed boilers. A contractor recently has been selected to undertake a waste sampling program for emerging energy technologies. Samples will be distributed to several government laboratories that will be responsible for characterization of the solid wastes and sludges. Details of this program are still in the planning stage.

A request for proposals (RFP) recently was issued for the companion program of field studies for disposed solid wastes from advanced energy processes. This will be a major effort, intended to characterize the extraction and subsequent migration of regulated constituents of advanced processes wastes, as well as those factors which influence extraction and migration (such as soil attenuation and evapotranspiration). Sampling and monitoring at four sites over a several year period are contemplated. This program is still in the procurement stage, pending a revision to the original RFP. A start-up program is expected to begin in late 1985. It will be highly complementary to another major field program being carried out by the Electric Power Research Institute (EPRI), discussed below.

Another project planned for this year involves the study of new methods for extracting energy from existing coal preparation plant wastes. Such wastes typically contain several percent of the feed coal heating value which is unavoidably discarded with preparation plant refuse. This study will examine the potential for extracting a liquid product based on pyrolysis of the wastes. In another study, the feasibility of using energy derived from coal cleaning wastes to generate sintering conditions capable of producing highly inert, sintered granules of waste products of superior durability and resistance to chemical attack will be investigated. Additional work on the characterization of coal preparation plant wastes (physical cleaning processes only) also is planned for this year, focusing on the organic, inorganic, elemental and mineral composition of the liquid and solid wastes from an Illinois No. 6 coal cleaned by heavy media separation.

Longer-term DOE program plans call for continued emphasis on characterization studies to identify potential environmental problems for conventional and emerging energy technologies as early as possible. Development of new control technology would follow in response to any identified needs. In the area of conventional coal combustion, current projects are directed at studies of wastes derived from low-rank western coals with high alkaline ash content. These studies would expand the current data base on fly ash, bottom ash and FGD wastes for conventional power plants. The analysis of institutional factors affecting solid waste disposal also is envisioned within the long-term DOE program plan, though no specific projects are currently underway.

Other Waste Management Programs

Within the federal government, the DOE/FE waste management program currently represents the principal R&D activity concerned with coal utilization technologies and related environmental control processes. While the EPA is extensively involved in the regulation and management of solid and liquid wastes, it is primarily concerned with hazardous and toxic materials, which do not presently include coal-related wastes to any significant degree. Thus, while EPA R&D programs in recent years have examined coal combustion and related environmental control technology wastes in some detail, there is no continuing R&D program in this area at this time. The last major effort was a recently completed multi-year program of waste characterization and field studies to determine the nature and fate of waste constituents from actual power plant disposal sites, particularly as it related to the potential for groundwater contamination. The results of this R&D study also are being used by the EPA Office of Solid Waste Management in conjunction with regulatory requirements under RCRA regarding the classification of wastes as either hazardous or non-hazardous. While a comprehensive report to Congress on the situation with regard to conventional power plant wastes still remains well behind schedule, the results of tests to date have largely mollified earlier concerns that such wastes might generally be found to be hazardous. Thus, current research efforts at EPA related to the clean use of coal are directed primarily at advanced and retrofittable air pollution control technologies, with little or no new work currently planned in the solid waste area.

The largest private R&D effort in the U.S. related to the management and control of coal-related solid wastes currently is found at the Electric Power Research Institute (EPRI). Two major programs are underway. One is a long-term (10-year) $50 million program of Solid Waste Environmental Studies (SWES) to develop data and methods for predicting the fate of constituents present in solid wastes at utility disposal sites. The ultimate goal of this project is to develop and validate geohydrochemical models for predicting the release, transport, transformation and environmental fate of chemicals associated with utility solid wastes. It emphasizes basic studies of waste leaching chemistry; transport of solutes in groundwater; chemical attenuation of solutes in the subsurface environment; evaluation of existing predictive models; and evaluation of groundwater sampling methods and related field measurement techniques. The utility wastes currently being emphasized are fly ash, bottom ash, FGD wastes, mixtures of FGD wastes and ashes, and oil ash. Wastes which may be considered in the future include those from coal cleaning, waste reprocessing, and advanced coal combustion technologies. This program, begun in 1983, relates closely to the planned DOE program of field studies of emerging energy technologies scheduled to begin this year. Close communication between the EPRI and DOE programs is anticipated, though they will remain separately funded.

A second EPRI effort, set to begin early this year, will focus on waste management systems for five advanced methods of sulfur dioxide control for electric utilities: atmospheric fluidized beds; furnace limestone injection; dry sodium compound addition; spray drying of calcium; and advanced coal cleaning. These are of interest because solid waste products from these processes have physical and chemical properties different from those of fly ash or scrubber sludge from conventional coal-fired power plants. For example, in all cases except the coal cleaning residues, fly ash will be intimately mixed with sulfur-bearing reaction products, and there will be a greater quantity of waste product to handle. Compared to "conventional" wastes, those from calcium-based processes will contain significant levels of unreacted lime, while sodium-based processes will produce wastes with higher levels of soluble sodium compounds. For coal cleaning refuse, the acidic nature of the leachate and its potential to release heavy metals are among the areas of concern. In all cases, differences in the nature of waste materials could require changes in current waste management practices. This could have a substantial impact on the overall economics and viability of these developing technologies. The objectives of the EPRI study are thus focused primarily on the characterization of these wastes; the design of appropriate waste management systems for each process (including an evaluation of different liners that provide a barrier to chemical transport); and the identification of potential by-product utilization methods and applications for waste materials. These studies will involve the acquisition of waste samples from various pilot and demonstration facilities, and will be carried out over the next 3-4 years. The annual R&D budget for EPRI's waste disposal programs is comparable to that of the DOE/FE Waste Management Program, and is larger if waste utilization R&D also is included.

Finally, we note that a variety of other organizations, such as the National Ash Association, also are involved in coal-related waste management R&D projects, including studies involving the recycle or reuse of waste products. Similarly, there have been substantial international activities in this area, both within individual countries (particularly England, Germany and Japan), as well as through international organizations (such as the IEA, OECD, etc.). While a detailed survey of all coal-related waste management programs is beyond the scope of this report, the interested reader will find many of these summarized and discussed in the technical literature.

V. CONCLUDING COMMENTS AND RECOMMENDATIONS

The DOE Waste Management Program as it is currently conceptualized represents a comprehensive and reasonable plan for addressing problems of solid wastes and sludges generated directly or indirectly by coal utilization technology. Its centerpiece is the characterization of wastes from conventional and advanced (emerging) energy technologies and environmental control systems. Included here are process emissions as well as laboratory and field evaluations of pollutant transport in the environment. Control technology development is envisioned as a second major element of the program. This would be responsive to any unmet needs or problems identified by waste characterization studies, and would include assistance and support to process development programs located in other parts of DOE. A third element of the waste management program design involves the analysis of institutional factors that may be critical to implementing waste management measures. Finally, the dissemination of information through reports, conferences, etc. represents the fourth major element of the program.

In practice, however, the DOE Waste Management Program has rather limited resources which substantially restricts the scope and nature of its activities. Thus, it is perhaps more properly viewed as representing a minimum acceptable effort to consider the potential environmental impacts of solid and liquid wastes associated with conventional and advanced coal utilization technologies. Fortunately, it is also complemented by an even larger R&D effort on the part of the private sector. Given the current level of program funding (approximately $2 million/year), and the DOE strategy of focusing R&D principally on long-range energy technology, the current priority of the Waste Management Program (i.e., characterization of wastes from emerging technologies) is indeed appropriate.

In the past few years, however, the overall funding level of the Waste Management Program has decreased by approximately one-third, with the possibility of further reductions in FY 1986. This, at a time when the current and potential future problems of solid waste disposal have increased in national concern, and the recognition of "cross-media" environmental impacts -- in which environmental problems are simply moved from one medium (i.e., air, water or land) to another -- has resulted in solid wastes becoming the final "sink" for undesireable materials from coal utilization technologies. Thus, the ability of the DOE program to adequately anticipate and deal with emerging environmental issues in this area in a timely fashion bears continual scrutiny.

The elimination of programs seeking innovative means of waste utilization and re-use is viewed with particular concern given the potential attractiveness of this option and its importance in situations where the lack of suitable disposal sites may limit or preclude certain energy alternatives. Projects of this nature, ideally cost-shared with private industry, are recommended for consideration in future DOE programs, along with the development of technology for waste disposal.

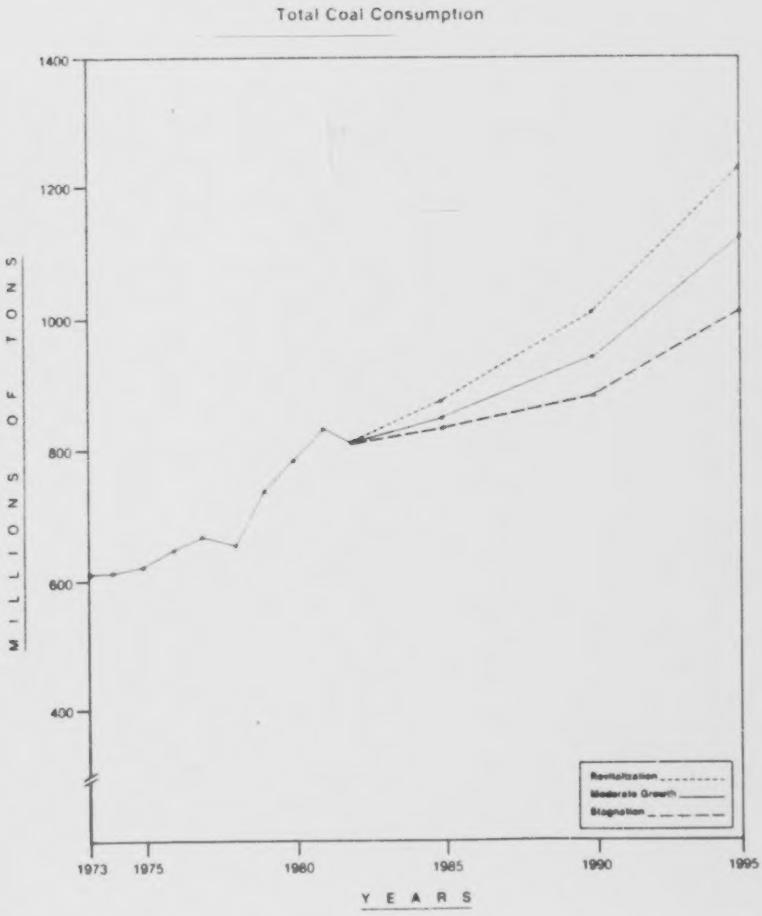
Table 1 provides an estimate of the total R&D funding requirements needed in the waste management area over the next five years. Included are private as well as public expenditures for R&D to address problems of waste utilization as well as waste disposal.

ESTIMATED FUNDING REQUIREMENTS
FOR SOLID WASTE MANAGEMENT R&D*
(millions of dollars)

AREA/YEAR	86	87	88	89	90	TOTAL
Waste Disposal	6	8	9	11	11	45
Waste Utilization	2	2	3	4	4	15
TOTAL	8	10	12	15	15	60

G. PROJECTED COAL UTILIZATION IN THE UNITED STATES

by: Joseph Mullen



Total Coal Consumption

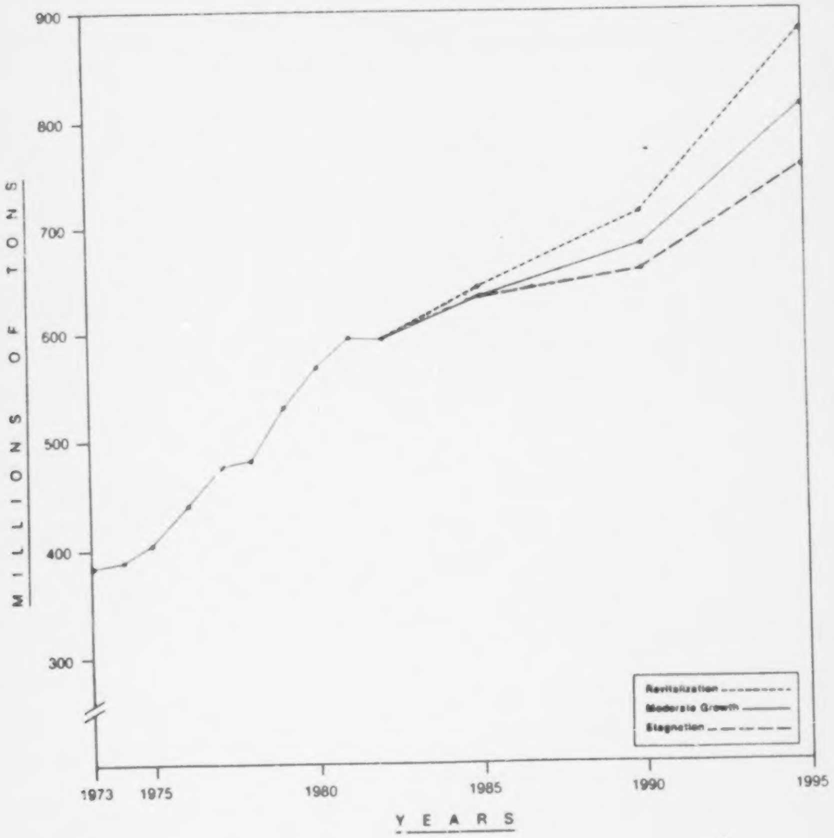
The two significant coal use areas are the utility and industrial markets, as it is here that the efforts of the Clean Coal Panel can and will have its major impact.

Electric Utility Market

Electric utilities, the principal market for coal, will continue to account for more than 70% of total coal use through 1985.

TABLE I

Electric Utilities



Coal's resurgence in the utility market in the post-1990 period results, in large parts, from its perceived role as the only feasible option for new base-loaded power generation. Although coal appears the logical choice, there are uncertainties which could have a negative impact on its use: better load management, cogeneration, conservation and plant life extension, no further oil-to-coal conversions, imported electricity from Canada and imported coals which reduce its competitive advantage, changes in public utility commission policies, and costs of pollution control compliance. These factors are compounded by the great uncertainty about future economic growth, structural changes in the economy, and the price and availability of alternative fuels. The size of the increase in utility coal demand through 1995 primarily will be determined by electricity demand growth and economic growth. Increased coal use is also sensitive to investment in coal-fired power plants and the competitiveness of coal's delivered price. Investment hinges on decision maker's expectations of future competitiveness of delivered coal. Delivered prices are also impacted by production and transportation costs, public utility commission policies, and costs of pollution control compliance.

Table I shows utility coal consumption in tons and average growth rates through 1995 under each of three scenarios--stagnation, moderate growth and revitalization.

Table II shows a comparison of average annual growth rates for electricity demand, by region and scenario.

TABLE II

COMPARISON OF AVERAGE ANNUAL GROWTH RATES FOR ELECTRICITY DEMAND, BY REGION AND SCENARIO

	Forecast Scenario (1982-1995)			NERC PROJECTION
NCA REGION	Stagnation	Moderate Growth	Revitalization	1984-1993
Northeast	+1.1	+1.6	+1.8	
East North Central	+1.3	+1.7	+2.1	
Southeast	+2.0	+2.5	+3.1	
West North Central	+2.5	+3.1	+3.9	
West South Central	+2.9	+3.7	+4.5	
West	+2.0	+2.5	+3.1	
TOTAL U.S.	**+1.9**	**+2.4**	**+3.0**	**+2.7**

Table III shows the total U.S. Electric Utility Capacity under the moderate growth scenario.

Many questions have been raised relative to the present and anticipated size of utility units. A review of information furnished by the utilities to the National Electric Reliability Council and to DOE's Energy Information Administration shows that large units appear to have peaked and that units in the range of 500 to 600 MW, or even still smaller units, will play the major role in new units expected to come on line through 2000.

TABLE III

TOTAL UNITED STATES ELECTRIC UTILITY CAPACITY, MODERATE GROWTH CASE

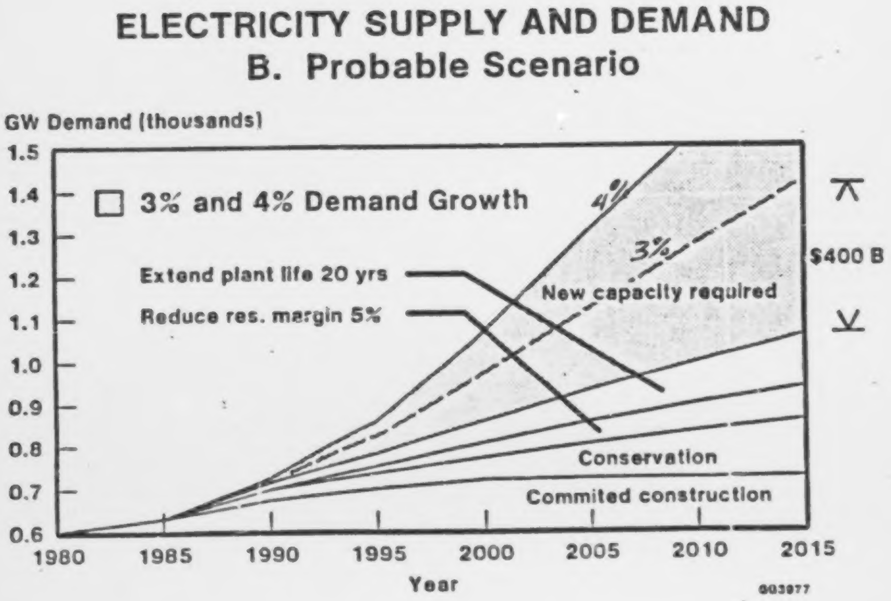
(thousands of megawatts)

YEAR	COAL	NUCLEAR	OIL/GAS	HYDRO/OTHER	TOTAL
NERC Historical					
1980	237.1	50.8	206.8	78.4	573.1
1982	252.3	55.7	196.0	82.1	586.1
Forecast					
1985	276.2	82.4	209.0	87.4	655.0
1990	291.8	111.6	214.0	91.1	708.5
1995	325.0	117.3	221.7	94.9	758.9
Net Additions 1982-95	+ 72.7	+ 61.6	+ 25.7	+ 12.8	+ 172.8

A significant factor impacting on the decision to delay or cancel new units is a relatively new trend directed at refurbishing existing coal-fired plants. A recent APAA report noted that most utilities are postponing retirement of larger units and are seriously beginning to consider the advantages of "refurbishing" units to give them life for another 20 to 30 years. It was stated that small operating units of 50 to 75 MW are likely to be retired while the 300-400 MW and larger plants could last up to 60 years with refurbishment. A similar report by a major equipment supplier calls attention to the fact that by 1990 20% of the nations' power plants will be thirty years old or older.

Unfortunately, there is little substantive data available beyond the mid 90's, but Figure I, based on data developed by EPRI, gives at least some insight into the early part of the next century. Obviously, demand growth beyond the mid 90's remains a question, but extension of existing plant life continues to be a significant factor.

FIGURE I


ELECTRICITY SUPPLY AND DEMAND
B. Probable Scenario
GW Demand (thousands)
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
☐ 3% and 4% Demand Growth
4%
3%
Extend plant life 20 yrs
Reduce res. margin 5%
New capacity required
$400 B
Conservation
Commited construction
1980
1985
1990
1995
2000
2005
2010
2015
Year
003977

The reductions in SO_2 already achieved have been significant. For example, EPA in February 1984 reported that nationally, total SO_2 emissions dropped 26% between 1973 and 1983. Emissions from power plants were down 17%, while utility coal use grew by 53%.

Furthermore, emissions will continue to decline as older plants are replaced and the results of the Clean Air Act's more stringent provisions on new plants are felt. The Electric Power Research Institute estimates that, based on these growth rates in electricity demand, SO_2 emissions from utilities will decline another 25 to 40 % over the next two decades if the new clean coal technologies discussed in this report are promptly implemented. If not, further SO_2 emission reductions will be substantially less. The Office of Technology Assessment shows emissions declining steadily to about 50 % of current levels by 2015; assuming a 40-year plant life, 2.5 % growth rate in demand and prompt implementation of new clean coal technologies.

Certainly, another factor impacting on the degree to which a utility must upgrade its existing facility is the acid rain issue. While no specific legislation has passed in the Congress, many have questioned the need for accelerated emission reductions based on the uncertain scientific base.

CONVERSION TO COAL

Conversion of oil and gas fired units to coal offers an additional market potential although there have been delays and cancellations. Many of the conversions which took place in the 1970s (6,500 MWO involved fuel switching by multi-fuel plants rather than significant modification of plant facilities. All conversions to date have geen in the east, as is the case for virtually all planned conversions as well. One utility in the west (Arizona) currently plans to convert 267 to coal.

CONVERSIONS BY REGION

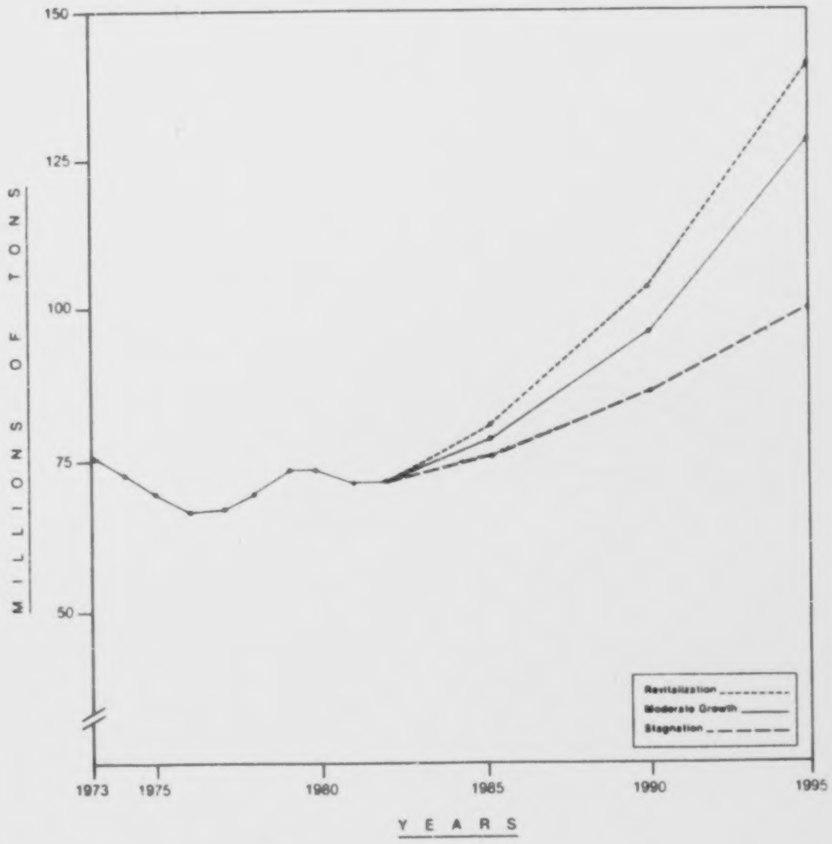
COMPLETED CONVERSIONS (MW) BY REGION THROUGH 1983

New England	
Massachusetts	1778 MW
Middle Atlantic	
New Jersey	226 MW
South Atlantic	
Delaware	234 MW
Florida	169 MW
Georgia	371 MW
Maryland	384 MW
Virginia	1920 MW
TOTAL	5007 MW

PLANNED CONVERSIONS (MW) BY REGION

New England	
Connecticut	250 MW
Massachusetts	664 MW
New Hampshire	139 MW
Middle Atlantic	
New York	750 MW
South Atlantic	
Florida	361 MW
South Carolina	580 MW
Virginia	638 MW
Mountain	
Arizona	267 MW
TOTAL	3649 MW

Industrial/Retail



INDUSTRIAL/RETAIL MARKET

The Industrial/retail market of 72 million tons in 1982 is expected to expand uniformly to 100-140 million tons in 1995. Future coal consumption depends not only on economic recovery, but more importantly on the economy's capacity to sustain growth.

Table IV gives some insight into the historical and projected industrial/retail market through 1995 by region.

TABLE IV

INDUSTRIAL/RETAIL COAL CONSUMPTION BY REGION
(millions of tons)

	Historical			Forecast		
CASE	1973	1980	1982	1985	1990	1995
Eastern United States						
Stagnation	--	--	--	56	62	72
Moderate Growth	67	58	53	56	70	95
Revitalization	--	--	--	60	75	104
Western United States						
Stagnation	--	--	--	20	24	28
Moderate Growth	8	16	19	21	26	33
Revitalization	--	--	--	21	28	36
Toal United States						
Stagnation	--	--	--	76	86	100
Moderate Growth	75	74	72	79	96	128
Revitalization	--	--	--	81	103	140

The industrial/retail market faces many of the same issues faced by utilities. Of significance is the age of existing equipment. Table V shows that while 70% of the industrial boilers utilizing oil or gas are 15 years old or greater, 95% of the coal units are 15 years or older.

TABLE V

INDUSTRIAL BOILER AGE PROFILE
BY PERCENT OF FUEL TYPE, 1982

	Less Than 15 Years Old (Percent)	Greater Than 15 years Old (Percent)
Coal	4.5	95.5
Distillate Oil	31.6	68.4
Residual Oil	27.2	72.8
Natural Gas	28.3	71.7

As noted, coal demand will continue to rise, but new coal fired units may play a lesser role, with refurbishment units becoming a major factor. Thus, it appears that in the near term, the efforts of the Clean Coal Use Panel may have a more significant impact on the long term need to replace existing capacity with new facilities.

APPENDIX A

THE SECRETARY OF ENERGY
WASHINGTON D C 20585

April 27, 1984

Mr. Ralph S. Gens
Chairman
Energy Research Advisory Board
4046 SW Jerald Court
Portland, OR 97221

Dear Mr. Gens:

A vital component of the Nation's energy mix, coal generates nearly half of our electric power and is a major industrial fuel. Since it is one of our most plentiful resources, its use is expected to increase during the coming decades. Finding ways to burn coal more cleanly and economically is a matter of very high priority. It is essential that the Department of Energy focus its research and development programs on those technologies that have the greatest promise, both in the relatively near as well as longer term.

Many technologies are being explored by the Federal Government and the private sector, in the United States and abroad, that could potentially be used to limit the undesirable consequences of coal combustion. Technologies used before, during, and after combustion are at various stages of development and present differing cost and effectiveness uncertainties. In this regard, it is important to understand the options available for replacement and retrofit of aging plants with advanced coal use technology.

In order to improve our ability to deal with coal combustion technology, I am asking the Energy Research Advisory Board to assess the status of the principal technologies for the clean use of coal, including a comparative assessment of their potential appropriateness in various situations. For each technology, you should review:

- the current DOE, private sector, and foreign R&D effort;
- the relative cost-effectiveness of alternative technologies for the clean utilization of coal resources;
- the adequacy and timing of this work in reference to the national need.

This study should help to ensure that the R&D activities will provide an adequate range of emission abatement technologies for application as they are needed. The Assistant Secretary for Fossil Energy and the Director of the Office of Energy Research will provide staff support and assistance for this important task. I would appreciate your completing this assignment by November 1984.

Sincerely,

Donald Paul Hodel

DONALD PAUL HODEL

Mr. REICHL. I think it would be helpful a little to spend a minute on considering the scope of what we have said and where the R&D efforts on clean coal use fit in the overall R&D picture. I believe total Government expenditures in energy R&D range between $3 and $3.5 billion, of which the specific areas of interest would be $150 million on fossil energy—that is the budget request for 1986—and out of that $150 million about $55 to $57 million is specifically earmarked for clean coal use. I should admit there are various ways of analyzing, or categorizing these numbers. This happens to be the simplest one that I believe is valid.

What you can see here is that the percent of total Government R&D spent on clean coal use is in the range of 1 to 2 percent of the total. I think that is the important figure to remember for a moment.

Now, as we have already heard, and I would like to reemphasize this, there is really excellent agreement between what the Department's in-house people say about the subject and what the ERAB report says. The only point of disagreement is the one that has been discussed here, which is a matter of policy and not of technology selection or anything.

In a nutshell, the panel suggests that the figure should be increased, and we are saying that because we expect, and I think most people expect, the use of coal generally to increase as time goes on. It is not a question of speeding up or increasing the use of coal as the main concern, but rather to cleaning up the use of coal. Coal is inherently a difficult fuel to use without some emissions, and it is that area, which is really health related, which suggests that an increase of attention should be given by the Government to this area.

The assumption here—rather, the conclusion of the study was that we expect that over the next 20 years coal use would remain largely in the area of combustion, maybe up to 90 percent of use, and that again the majority would be in large utility-type boilers. The balance would be in industrial boilers, which are less significant.

Now, equally important would be the fact we also expect that over this same period most of this coal combustion will continue to occur in existing boilers, and as a result, some priority should be assigned to the issue of technologies to development and demonstration of technologies which can be retrofitted to the existing facilities.

To just repeat it again, the main problem as we see in the energy picture for the next 20 years as it relates to coal is cleaning up the existing stations. I think that is the message we would like to leave.

Now, when it comes to how to do this the panel has noted, as has DOE, that there is a wide range of alternate technologies which must be considered, and the preferred answer will be extremely site specific. There is no computer you can go to and prioritize and say we have to go 1, 2, 3, because 1 is more important than 2. The reasons why this is so depends on many factors at each site. And just to name a few so that you get a feel for this, it is the size of the plant, the age of the plant, remaining life of it, the type of coals that are available, the price, the design of the plant that exists, even the space that is available to add facilities to clean up—all of those affect the preferred choice at any given site. So, as Mr. Vaughan has said, a proper R&D Program should offer a choice, the widest possible choice of alternate technologies.

Now, how does one then choose? And there I think the report makes it quite clear. We say you leave that to the marketplace, and the way that is expressed, as we suggest, is by the cofunding that is being offered. I think that in itself will be a self-regulating system by which those technologies which the private sector considers worthy of support will get support.

Of course we are coming to the point now where we have this one point of disagreement. We feel that the R&D Program is ultimately successful only if it is commercially accepted, and the key step required for this varies, of course, between technologies and industries. And there is a peculiar problem here. As we have said, most of the coal use will be in large utility applications. The utility industry is peculiarly sensitive to any innovation that puts at risk the supply of electricity; therefore, its acceptance requires demonstration on a very substantial scale. That doesn't mean you always have to go out and build a new plant from scratch. In most cases it is using an existing facility, but a big one, to test a new technology. That is quite costly.

Now, at the same time the utility industry has a research budget that is prescribed by something like 50 different utility commissions around the country. And while they do spend about $300 million annually through their Electric Power Research Institute, this is not enough in the view of ERAB to answer the problem that is now before the Nation.

We certainly completely agree with DOE on the need to pursue above all fundamental research and basic research related to coal. There are several examples of it that are noted in the report, but we have no disagreement with DOE in that area.

I had not planned here in any way go through the listing of the individual subjects. That would take too long. You will find a good discussion in the report on each area. But to give you a comprehensive view, let me briefly sum it up this way. Mr. Vaughan just mentioned that the total proposals received came up to a total cost of $8 billion. That is not the kind of figure, of course, that we have come up with here. What ERAB said is that if all the technologies, and there are about 12 to 15 listed specifically, some areas that are generic. If all of them were pursued through to commercial acceptance, through the demonstration level, the total cost of such a program might be as high as $2.4 billion. That was the number we came up with. That would be spent over a period from 5 to 7 years.

It is obvious that not all of these will see the light of day, so that the total program in the end will cost much less than that. And of course most important, that is not suggested as the amount of money to be spent by DOE. I think we have been very aware of the budget restrictions that the Department has to comply with, and it is only our view, ERAB being an independent think tank, that we think if you go from 1½ percent to something like 4 percent of the total R&D budget, considering the importance of coal in the energy picture for the next 20 years and the importance of the health aspect and the cleaning up, that that would be a change in the emphasis that would be quite defensible. It doesn't say that you need to get the money from any specific source. We did not get involved in that.

I would also like to add a point here that I think is important. I would think that it is important if you can somewhere get this policy matter resolved, but I would be very concerned if we come up with a set of specific technologies which are mandated by Congress to be developed. I think that would be clearly the wrong thing to do. I think the competence available to DOE in making that decision is totally there; and furthermore, if you use the mechanism of cofunding as using a marketplace response to what is preferred, that would cover the issue of what is the right priority.

I would like to stop at this point and answer your questions.

[The prepared statement of Mr. Reichl follows:]

ERIC H. REICHL

25 LISMORE LANE, P.O. BOX 786, GREENWICH, CONNECTICUT 06830 • PHONE (203) 661-9723

THE ERAB REPORT ON CLEAN COAL USE TECHNOLOGIES

Statement by Eric H. Reichl
May 8, 1985
before the House Committee on
Science and Technology,
Hon. D. Fuqua, Chairman

Mr. Chairman,

My name is Eric H. Reichl* and I am appearing before your Committee to discuss some aspects of the report on Clean Coal Use Technology about to be issued by the corresponding panel of the Energy Research Advisory Board, or ERAB, of the Department of Energy.

I have been a member of ERAB since 1979 and I am the chairman of The Clean Coal Use Panel which was established in April 1984 in response to then Secretary Hodel's request. He asked ERAB to review the subject and to recommend an appropriate program for Research and Development for DOE.

We have been most fortunate in being able to assemble an outstanding group of experts from within and outside ERAB, who could bring to bear their wide experience with the several areas of clean coal use. To give a logical structure to the report, the subject which is quite broad and diffuse was divided into three major sections: these are Pre-Combustion systems, Combustion proper and Post-Combustion. Combustion was subdivided into Conventional Combustion, essentially pulverized coal burners, and fluidized bed combustion, and a section on solid-waste management was added. Further, to obtain a feel for the scope of the future markets for coal and the specific clean coal technologies to fit them, Mr. Joseph Mullan, V.P. of the National Coal Association, joined the panel and prepared a projection of coal utilization in the U.S.

Each area was then assigned to one or two panel members for review and recommendations. The key individuals and authors of their respective sections were as follows:

Coal preparation: Mr. William N. Poundstone, retired Executive Vice President of Consolidation Coal Co. and Dr. Edward Rubin, Director/Center for Energy & Environmental Studies/ Carnegie-Mellon University

Conventional Coal Combustion: Mr. John Landis, Senior Vice President, Stone & Webster Eng. Co. and Mr. Frank Princiotta, Director of Industrial and Environmental Laboratory/EPA

Fluidized Bed Combustion: Mr. Kurt Yeager, Vice President/ EPRI-Coal Combustion Division

Post Combustion Control Technology: Mr. Larry Papay, Senior Vice President/Advanced Engineering, Southern California Edison Co.

Waste Management; Dr. Edward Rubin (see above.

---

*A brief Resume of my experience is attached for your records.

Throughout the preparation of the reports the panel members visited selected DOE facilities and received full cooperation and help from DOE staff at all times. It is a pleasure for me to acknowledge this assistance at this occasion. And I would especially like to recognize the substantial time and effort contributed by the panel members, all of whom are heavily engaged in their regular activities in industry, academia or in government service.

The seven separate sections of the report were circulated for comments to all panel members, and the entire panel met three times for discussion to assure as good a consensus as possible. A summary was prepared by me to highlight the major findings.

The finished DRAFT was then submitted to the entire ERAB for consideration at the quarterly meeting of the Board on May 1-2.

Speaking now for the Coal Use Panel as a whole I would like to point out for you the key findings about DOE's R&D program on Clean Coal Use Technology, but before I list them I would like first to set the stage by noting a few general observations:

° An order of magnitude set of figures for all energy related R&D expenditures at this time shows the following figures in $'s per year:

Private industry, companies:	$3,500.- Million (including ($3,000 MM for oil exploration)
Private industry, regulated:	$450.- Million (EPRI plus GRI)
Government: DOE, Total:	$3,100.- Million ('86 Request, excluding weapons)

To this one might add, maybe $4-500 million/yr for the Synthetic Fuels Corp. if it is permitted to complete the limited program it has proposed.

Thus the total U.S. energy related R&D could approach $8 Billion; $3.6 of this spent is spent by the government.

° The figure includes some $150 million requested by DOE for FY '36 for Fossil Energy, of which some $55 million aim at Clean Coal Use. This then would represent about 1½% of all Government R&D related to energy.

° In a nutshell, Mr. Chairman, the panel suggests that this figure be increased by a factor of 2 to 3. This is obviously not any massive rearrangement of the R&D budget as a whole and should be achievable within the available total funds.

° The panel suggests that in view of the quite obvious, major and increasing, contribution the combustion of coal will make to U.S. energy supply over the next 25-30 years, it warrants immediate and significant attention, larger than it is currently receiving. This applies both to Government and the private sector. The evident need is for improved cleanliness when coal is used as fuel.

That is the key message of the panel's report. Now allow me to note a few observations made by the panel:

° Coal consumption in the U.S. will approach the billion ton per year level in the early 1990's. Some 80% of it will be consumed by electric utilities and a good part of the balance in industrial boilers and furnaces.

This combustion is THE coal use which requires attention with main emphasis on the large utility coal burner.

° Equally important is the fact that the bulk of this coal combustion will continue to occur in existing boilers. This then sets a priority on clean coal use technology which can be retrofitted to existing facilities.

° The panel further notes that there are a wide range of alternate technologies to be considered and the preferred answer will be extremely site specific. Therefore there is absolutely no way to select one preferred approach.

The relative cost effectiveness at any given site depends on a large number of factors which will vary all over the place.

To name a few: size of plant, age, type of coals available, at what price, plant design, even available space and existing or expected, regulations on emissions, etc.

A proper R&D program must offer a choice of approaches leaving selection of the technology to the user.

° In effect the panel notes, that the marketplace will be the best selection mechanism for choosing the technologies which deserve support.

In turn this is best determined by insisting on a major private sector contribution and this must increase as a technology moves into the critical and costly demonstration phase.

° This led the panel to a particularly important comment on DOE's R&D policy.

No R&D program is ultimately useful unless it leads to commercial acceptance. The key step required for this varies of course among industries, but electric utilities must be uniquely wary before any innovation can be adopted and there is simply no way to bypass the need for large, even full commercial, scale testing.

As matters stand, DOE policy has frequently kept the Department from participation in such test-, or demonstration programs. The panel recommends that DOE do participate, or even lead, in such tests.

This does not deny the need for major private sector contribution. In fact DOE may be a less than 50% contributor, but DOE leadership is needed.

° The panel fully agrees with DOE on the urgent need for increased exploratory and basic research. In fact our fundamental knowledge has been exhausted and we badly need new insights. DOE has unique capabilities in the several National Laboratories which should be mobilized in this direction. I want to be clear, the panel is not thinking in terms of engineering, or process-development, but of basic knowledge about the composition and distribution of mineral matter in coal, its behavior in a flame, etc. One of the finest examples of such work is the laser supported combustion research at Sandias Livermore laboratory, to give you a feel for the type of study we need.

DOE is quite properly planning to continue or even to increase Basic Research in coal related subjects. Incidentally, in terms of cost this is minor compared to the overall budget.

° Time obviously does not permit us here to go into any detail of the several specific suggestions the panel made in its report. I would like permission to place the report into my testimony as an addendum and urge you to read the individual sections where the rationale for the various technologies is presented.

You will find near the end of each section a Table of the order of magnitude, in dollars and time, required to bring the technology to commercial acceptance. Be sure to understand this is NOT the amount suggested for DOE support, but the total cost of a program.

° To give DOE a ready comprehensive view these figures were summarized in a table (on pages 15A to E) and to be consistent, the total costs of a possible 5 year program for the years '86 to '90 were given for each technology. The total, about $2.4 billion includes:

$120 million	for Precombustion, or cleaning technology
$628 million	for Conventional Combustion
$930 million	for Fluidized Bed Combustion
$100 million	for Airblown gasifiers, or 2-stage combustion
$562 million	for Post-Combustion, flue gas clean-up, and
$ 60 million	for Waste Management.

It should be obvious, that not all of these options, some 15 to 20 are discussed in the reports, will come to fruition, thus the total spent would be substantially less.

And finally, the report suggests an area of magnitude contribution towards this overall program which might be appropriate for DOE. The panel's figure is about 30%, or $740 million over the 5 years. This compares to $275 million, DOE would contribute if the '86 Budget request were maintained without change thru 1990. This corresponds to some 2 3/4 times greater efforts in clean coal use R&D than is now contemplated.

Although this is a major change for this program, it is not major in the context of DOE's Total R&D budget. But it is an important adjustment in emphasis which the panel believes to be called for if we want to keep the coal option open.

° I have tried to give you a brief overview of the ERAB report on Clean Coal Use Technology and would like to conclude by thanking the Committee for this opportunity to present our views.

I shall be happy to try answering any questions you may have.

BIOGRAPHICAL RESUME: ERIC H. REICHL

Personal:	Born in Vienna, Austria, December 3, 1913 U.S. Citizen - Married, two daughters
Education:	Equivalent degree to MS Chemical Engineer Technische Hochschule - Vienna, 1937
Employment:	
1938	Babcock & Wilcox Company Field Engineer (construction)
1938-1944	Winkler-Koch Engineering Company, Wichita, Kansas (and subsidiaries) Research, plant design - construction, operations
1944-1946	Stanolind Oil & Gas Company, Tulsa, Oklahoma (now Standard Oil of Indiana) Process research on synthetic liquid fuels including tour of duty with U.S. Navy as civilian technician to evaluate German synthetic oil industry - January - June 1945
1946-1948	California Research Corporation (Standard Oil of California) Process Research - Petrochemicals
1948-1954	Consolidation Coal Company - Research Manager
1954-1962	Consolidation Coal Company - Director of Research
1962-1974	Consolidation Coal Company - Vice President, Research*
1974-1978	Conoco Coal Development Company - President (subsidiary of Continental Oil Co) Retired 12/31/78
1979-	Consultant
Professional Associations:	American Chemical Society American Institute of Chemical Engineers Member, National Academy of Engineers Member, Energy Research Advisory Board (ERAB)/DOE Past Member, Research Coordination Panel/Gas Research Inst. Member, Gov't. Tech. Adv. Comm./USERDA 1973 Chairman, Coal Task Group/National Petroleum Council Energy Study - 1972 Chairman, Coal Conversion Panel/National Academy Energy Study (CONAES) - 1977 Past Member, Liaison Committee of International Institute for Applied Systems Analysis

*Note: Consolidation Coal Company's research and development program includes pipelining of coal; conversion to liquid, gases and chemicals; sulfur recovery; continuous coking.

3/19/82

Mr. Fuqua. Well, thank you, very much.

On that point that you mentioned, in making the marketplace the selection mechanism, from what you are saying you feel that Congress should not get involved?

Mr. Reichl. Not in the sense of——

Mr. Fuqua. Of specific technologies.

Mr. Reichl [continuing]. Specific technologies.

Mr. Fuqua. How would the marketplace work in this way? Could you outline that to us as you envision it?

Mr. Reichl. Well, if the Department were to consider, say, the 10 technologies or areas that we have outlined, which they, themselves, have also selected of course, and tried to develop projects in each area, and then ask for proposals to come in which require a minimum of cofunding that is in the range that they feel appropriate, and it ought to be very high. Then, that would be a practical mechanism by which that can be achieved.

Mr. Fuqua. You also indicated that you felt that DOE probably would be a less-than-50-percent contributor.

Mr. Reichl. Yes; I would have thought that on the whole in that range. It wasn't I, please. That is the panel and ERAB that says that. That a range of about one-third would be a reasonable figure, although that need not apply to any one specific area. For the program as a whole, a one-third contribution might be adequate.

Mr. Fuqua. Should we include that in the language, that it was not the intent of Congress that any more than 50 percent be DOE funding, or should that be a higher figure, or should we not address that?

Mr. Reichl. I would think it is a——

Mr. Fuqua. Congress is going to be concerned about that.

Mr. Reichl. Yes; I think your question is appropriate all right. The problem is that different types of projects may call for different levels of proper private sector contribution. And I wouldn't know at this moment how to answer you.

Mr. Fuqua. Write a formula.

Mr. Reichl. Yes, how to write a formula. I would have thought that the subject is of more importance at the larger scale tests. That is obviously the problem. I would like to think about it a little bit before I say anything on that subject.

Mr. Fuqua. I would appreciate maybe getting your comments.

Mr. Reichl. Maybe I could do it in writing.

Mr. Fuqua. Yes, that is what I meant. In writing, after you have had a chance to reflect on that. Because I think what you are saying is a very important key as I look at it. You then determine the technologies that are most available and that the people feel have the best potential by the amount that they would be willing to put up.

Mr. Reichl. Correct.

Mr. Fuqua. So that, along with the other technical part of it, would be a very good criterion.

Mr. Reichl. It is self-controlling criteria, in answer to Mr. Walgren's issue. To give you a good example, you will find in the ERAB report a very large dollar figure on atmospheric fluidized bed and an almost equal figure for pressurized fluid bed. It is quite clear already from what Secretary Vaughan said that the atmospheric bed could require relatively little further contribution from DOE. It is, indeed, moving along well in the private sector. That is not true for the pressurized.

So, a generic formula somewhere needs to be thought through fairly carefully before we say anything.

Mr. Fuqua. Thank you very much.

Mr. Boucher.

Mr. Boucher. Thank you, Mr. Chairman. I have just a couple of questions.

When Secretary Vaughan was testifying earlier today, he indicated that one of the reasons the Department has made a recommendation not to have Federal participation and cost sharing for the construction of demonstration facilities for emerging clean coal technologies is that it would place the Federal Government in the position of competing with private industry that may be developing these technologies on its own.

Now, it seems to me that he is wrong in that respect. That by having the Government participate and accelerating the development of these technologies, we are advancing the interests of the industry as a whole. That is my personal position.

But I would be very interested in hearing what the Research Advisory Board has to say about that. What is your view of the statement that the Secretary made concerning the Government's participation and whether or not that, in fact, is competition with the private sector?

Mr. Reichl. Well, I would have to agree with Mr. Vaughan on this, and I think maybe his answer wasn't quite properly understood or clear. What he said was that in a specific case, suppose you take a specific type of fluidized bed development which is being pursued by a private company, and now the Government appears on the scene and says, "We'll have another one that I think we will support." That is, in effect, an unfair competition.

There have been several instances where the private sector has, in fact, made its view known. Not only here, but at the Synthetic Fuels Corporation we run into exactly the same problem. In coal/water mixtures, for example, where we had classified, categorized it as a proper subject for synthetic fuels development—and I was the one who did it to some extent. However, we had some major corporation say, "We are doing this job, we don't need your help, please stay out of it." So we stay out of it.

I think that is applicable here. But where such an area is not yet in the private sector I think there is no objection to do this here.

Mr. Boucher. I sense that the Secretary was using a philosophy which would keep the Government from competing with private industry as a rationale for the Government not participating in cost-sharing projects at all. Now, perhaps I misunderstood his statement. But I would assume that your conclusion would not be to that end.

Mr. Reichl. Would not be to that end. But I don't really think that is what he meant.

Mr. Boucher. All right.

Mr. Reichl. I don't know what he meant.

Mr. Boucher. Well, I am certainly not asking you to speak for him.

I notice that you suggest that market forces should drive the decisions as to which particular projects are selected for Government funding. Do you suggest that the indicator of the market's choice would be the percent of private funding that would be forthcoming for a given project? Should that, in your opinion, be the sole criterion, or should there be other considerations?

Mr. REICHL. You have to, I think, blend several criteria that in the final analysis become personal, and I don't know how you ever override that. If the man in charge of the decision in DOE happens to be in, you know, his Department says fluidized bed combustion, in the final analysis he has to decide what he wants to support and you have to live with his judgment.

The important thing is to have people that have good judgment, and I think you are well-served on that score. There is no computer you can go to that really will come out and say that is the obvious one to support.

Mr. BOUCHER. So while this would be a primary consideration, the Department should not limit itself solely to an evaluation of the percentage of private industry cost share in deciding which projects to fund?

Mr. REICHL. Absolutely not. For instance, you have to see what the competence is of the man who promotes it, sponsors it. You have to look at the data base that is behind it. You know, one that offers more money may have a much poorer data base, and that may be an unreasonable risk. You have to finally live with the personal judgment of the people in charge, and I think we should be perfectly willing to do that.

Mr. BOUCHER. Your testimony has a summary of the amounts of funding that are being spent on coal research and development nationwide. I wonder if you could give us some indication, if you have this information available, of the amount of dollars that private industry is spending on either precombustion or combustion coal research and development.

Mr. REICHL. I certainly do not have that here. It is not an easy figure to come up with precisely. I had in the testimony an overall picture of about $3.5 billion in energy-related research. Most of it is in petroleum exploration. As far as the coal, the private sector coal-related R&D, I can generically tell you from experience it is a small amount compared to what we are talking about.

Mr. BOUCHER. Could you acquire those figures? Is that at your disposal?

Mr. REICHL. Well, let me say I could try. Whatever help I need, I am a one-man show. I don't have any access to that.

Mr. BOUCHER. Well, if it is possible to obtain it, I would be interested in seeing that. There is a coal company in my congressional district which spends about $1 million annually of its own dollars on combustion research, which I think is a fairly substantial contribution for one company to make. But I am not aware of what other companies are doing. And if there were some way to collect that information, it would be very helpful.

Mr. REICHL. I will try. There are several agencies that have made a point of collecting it annually. Maybe we can get it that way.

Mr. **Boucher**. Thank you very much. I want to commend you for the statement that you have presented this morning, and I, for one, appreciate very much your conclusions.

Mr. **Reichl**. Thank you.

Mr. **Boucher** [presiding]. My time has expired.

Mr. Packard.

Mr. **Packard**. Thank you, Mr. Chairman.

In your testimony you indicated that only a small percentage of the research and development in all of our energy areas is targeted toward coal research. What figure, or what percentage do you feel our total research program in energy now is targeted toward coal, and how much do you think should be?

Mr. **Reichl**. Well, oddly enough, it isn't quite as easy to come up with a quick answer to your question. The specific budget request, as I understand it, for fossil energy R&D in DOE is about $150 million, which is down from $250 million last year. These figures vary from month to month, and I have got to excuse myself if they are not exactly precise. Of that, roughly one-third, or about $50 million, is narrowly aimed at clean coal use.

First, let me say that there is, of course, coal-related research, and you have got to classify it as that, in the Synthetic Fuels Corporation, which is a very much larger figure. The reason being that the kind of projects that are required to bring synthetic fuels on are much larger than those demonstrating clean coal use technologies. Order of magnitude, over there you are looking at projects costing a half to $1 billion class. For development to commercial scale of clean coal use, you are looking at the $50 million to $200 million class. Order of magnitude. That is total cost, not per year, of course.

Now, the question you asked, is the percent, is the distribution of R&D effort that DOE places on, say, fusion, nuclear, coal, oil, appropriate? The first thing you have got to recognize is that different technologies require totally different amounts of money. The fact that we spend, say, half a billion annually on fusion, all of it government money, simply reflects the fact that that is the level that you must have to make any progress. Conversely, that is not required for coal.

I don't, again, think I can come up with a proper figure of what is an appropriate percentage of the total. But I do think within the fossil area I can do so. I feel that the distribution that DOE has in the clean use versus the rest of fossil is too low, and that a doubling of that effort would be appropriate.

Mr. **Packard**. In foreign countries, because of a variety of reasons, perhaps lower environmental standards than the United States has, the use or the consumption of coal I think generally is higher than it is in the United States, per capitawise at least.

Is foreign research and development ahead of or equal to or lagging behind or the commitment greater than we have here in the United States?

Mr. **Reichl**. I don't think that we have to apologize for our level of effort. I think it is often claimed that it is higher over other places. I don't think that is really right.

But the point you made I don't think is quite clear. Japan, for instance, as far as I know has tighter rules than we have in many areas; and oddly enough, it is the Japanese effort in clean coal use that is quite excellent. In all clean fuel use, there is plenty of work going on in Europe. But I don't think that, order of magnitude, we stand out either on the upper or low side.

Mr. PACKARD. Is there a sharing of information?

Mr. REICHL. Quite so. As you know, the Japanese have come over here and contributed to projects here. We have had full access and excellent cooperation whenever we have gone over there to get information from them. The technologies developed abroad are, of course, licensable in this country. And I don't think that is an issue per se.

I would say the international versus U.S. issue is not a major one. There was one project which I believe the ERAB report notes. We have contributed on pressurized fluidized bed combustion on a project in England that is supported not only by British, but it is German, British, and American money, which is a useful one and ought to be continued. But I don't think there is much to be said up or down.

Mr. PACKARD. Thank you very much, Mr. Chairman.

Mr. REICHL. Excuse me, Mr. Packard.

Mr. PACKARD. Certainly.

Mr. REICHL. You had asked the question of Mr. Vaughan about tax incentives and other incentives, other than coal. I wondered whether the gasohol program could not be looked at in that way. It seems to me that—you have depletion allowance on oil, you have substantial and major tax incentives for solar energy installations, which are linked to R&D somewhat, that are all in the billion-dollar class. Coal does not have anything like that.

Mr. PACKARD. Thank you very much.

Mr. FUQUA. Mr. Walgren.

Mr. WALGREN. Thank you, Mr. Chairman.

I just think that is some of the most effective testimony that I have heard given, and I certainly want to underscore that and congratulate you on the role that you have played in this.

I had the impression when I came to the Congress and looked at previous coal budgets that an awful lot of money was going to relatively few projects. And many of the reductions that the Reagan administration pursued were certainly justifiable in the sense that there was not a wide distribution of the funds, and certainly the program was concentrated.

You mention in your report that the wide use of congressional mandates in funding for specific projects raises some difficulties. Could you expand on that?

Mr. REICHL. Well, there are projects that DOE does support that are basically mandated by Congress and, to that extent, their freedom of decision of what they should or can do in certain areas, of course, is limited. I believe on the whole this has not been of great help in the overall picture.

Mr. WALGREN. You indicated in response to Mr. Boucher that you certainly had confidence in the DOE's judgment about the evaluation of these——

Mr. REICHL. Yes.

Mr. WALGREN [continuing]. And selection of projects at this point. I guess my concern is that we don't fall back into that pattern of concentrating all our funds on some project and, therefore, having to eliminate a lot of other research. I am wondering whether you feel that DOE could suggest or that we could follow some kinds of guidelines in this area in particular that would focus us in the right direction; that would not be project specific, but assure that the little moneys that we do put toward clean coal got the greatest effective result?

Mr. **Reichl**. Well, Congressman, I understand your concern. There is no reason to gainsay them. I think, on the other hand, I have to fall back on the fact that if you believe that the people in DOE are competent in the way they handle the funds they have available that what you are afraid of will not occur. Suppose they set up another *x* million dollars and then put it all in one project. That obviously would be a concern. I don't think that is likely to happen.

And if you look at the existing program that they are pursuing—we have noted in the report and we certainly feel that way—they have done a very good job in spreading what money they have over the area all around. There isn't a single area that they have not had some contribution, which speaks well for them. I think if the funds were increased we could count with assurance that they would do the same thing in the future.

Mr. **Walgren**. Your report mentions that for optimal allocation of resources that projects should be specifically reviewed with regard to a number of factors, including the contribution to emission control, the cost-benefit ratio, the timeframe, the probability of technical and economical success, and I guess the industrial need. Those seem to be certainly the things that we would instinctively take account of, or try to take account of, but I am wondering should we really push to set a framework by which these various projects could be judged so that we don't overly commit to one project which might not deliver, particularly in the clean coal area, as much help as we need.

Mr. **Reichl**. Mr. Walgren, I really would hope that we don't have to do that. I think what I have said before, I believe you could argue that the history of the way the people at DOE have handled this kind of an issue is quite comforting. That they will not do what you just considered as an obvious mistake. I think what you might remember is the period in the late 1970's and up to 1980 when about $1 billion a year was spent by DOE on fossil on two or three major projects. That was a mistake. They are certainly not in that frame of mind today. And from their report and from the contacts we have had with them, I would say it is not a concern.

I would be more concerned about any framework that you set up in legislation that then becomes far more of a bind on their decisionmaking than you want it to be. It is very difficult to write any rules that would cover all these criteria in a mathematical sense. It is odd that you bring it up. It is a subject that the ERAB wrestles with all the time. We are always asked: "Well, what criteria should we use?" And you never come up to a system of computerizing, I will use the term the "selection process" for R&D. It always has to contain a personal judgment factor that is overriding in the end.

Mr. **Walgren**. Well, I would just like to say that this is a very significant citizen contribution that I think has power to it that will be reflected in future Government policy. And you and the members of your committee deserve tremendous credit for what you have put together.

Thank you, Mr. Chairman.

Mr. REICHL. Thank you.

Mr. BOUCHER. Thank you, Mr. Walgren.

Mr. Reichl, we appreciate very much the contribution you have made and your presence here today.

Mr. REICHL. Thank you.

Mr. BOUCHER. Our next panel will consist of Mr. Gene Mannella, the director of the Electric Power Research Institute's Washington office; Mr. David O. Webb, senior vice president, policy and regulatory affairs, of the Gas Research Institute.

In view of the time, the Chair would ask the witnesses to please restrict their opening statements to approximately 10 minutes.

Without objection, the full statements of the witnesses will be made a part of the record.

The Chair recognizes Mr. Mannella.

STATEMENTS OF GENE G. MANNELLA, DIRECTOR, WASHINGTON OFFICE, ELECTRIC POWER RESEARCH INSTITUTE, WASHINGTON, DC, AND DAVID O. WEBB, SENIOR VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS, GAS RESEARCH INSTITUTE, WASHINGTON, DC

Mr. MANNELLA. Thank you, Mr. Chairman. Thank you for the opportunity to appear here today and present testimony. I have a very complete statement by Mr. Kurt Yeager, the vice president of our coal combustion systems division, which I would ask be inserted in the record in its entirety.

Mr. BOUCHER. Without objection.

Mr. MANNELLA. And I certainly express my thanks for allowing me to pinch-hit for him. As of 8 o'clock last night, he was still trying to figure out how to get from San Francisco, to Washington, to Beijing. He couldn't make it, so I am sitting in for him.

We have testified before on this subject, and I think that we have covered it rather extensively. What I would like to do today very briefly is to make a number of points. None of them are really new, but perhaps in putting them in the order that I composed them our support for this program will become clear.

First, coal is our most abundant energy source.

Second, 80 percent of the coal produced in the United States and 90 percent of the coal actually utilized in the United States is for production of electric power.

Third, electricity consumption has grown at almost exactly the same rate as the GNP over the past 10 years; that is, about plus 29 percent, even though the total energy usage during this period dropped by 1 percent because of extensive conservation measures.

Fourth, an average annual electricity usage increase of 2.5 percent per year will result in the need for 100,000 megawatts of new capacity by the year 2000.

Fifth, to meet any new demand, coal will almost certainly be the fuel of choice.

Sixth, environmental concerns cast a cloud over the degree to which coal utilization technologies must be upgraded to be viable options.

Seventh. advanced technologies for clean coal combustion are and have been under intensive development.

Eighth, these technologies must be demonstrated at utility scale in order to penetrate the marketplace.

Ninth, because it is an economically regulated industry where risk and reward are decoupled, the utility industry cannot underwrite the total cost of demonstrating these technologies on the scale and in the timeframe that will probably be required.

Tenth, and last, since an adequate, dependable supply of environmentally and economically acceptable electric power is a national imperative, the Federal Government must underwrite a portion of the cost and risk of bringing new clean coal technologies to the marketplace in an expeditious fashion.

Mr. Chairman, it is for these reasons that we support the National Clean Coal Technology Initiative.

I would be happy to answer any questions you might have.

[The prepared statement of Mr. Yeager follows:]

TESTIMONY

BY

KURT E. YEAGER
VICE PRESIDENT, COAL COMBUSTION SYSTEMS DIVISION
ELECTRIC POWER RESEARCH INSTITUTE

BEFORE THE

ENERGY DEVELOPMENT AND APPLICATIONS SUBCOMMITTEE

COMMITTIEE ON SCIENCE AND TECHNOLOGY

U.S. HOUSE OF REPRESENTATIVES

MAY 8, 1985

Introductory Statement

Mr. Chairman, Members of the Subcommittee:

I am Kurt E. Yeager, Vice President and Director of the Coal Combustion Systems Division of the Electric Power Research Institute (EPRI). I appreciate this invitation to meet with you to discuss promising clean coal technologies and opportunities for their accelerated development and application. These opportunities have significant implications for the electric utility industry and therefore are of great importance to EPRI.

The Electric Power Research Institute was established by the electric utility industry in 1972 to conduct a broad research and development program for the entire electric utility industry and its rate payers. EPRI's R&D mission is to develop new and improved technologies for electric power production, delivery and use, and to help accelerate their availability to insure an adequate supply of economic, reliable and environmentally acceptable electricity.

EPRI is supported by voluntary contributions from investor-owned, government-owned and cooperatively-owned electric utilities across the nation. During the next five years, EPRI will direct over $580 million to improving coal utilization. This commitment is based on the premise that coal utilization and environmental protection are mutually compatible and that improved technology is the key to compatibility. Answers are urgently needed for the important questions concerning coal utilization and the environment, if we are to make effective decisions concerning the stewardship of our national resources. Accordingly, EPRI and the utility industry are focusing on three fundamental issues:

- Defining what resources are at risk.
- Developing the technology necessary to control these risks.
- Determining where and when control measures can be most effective.

The scope and urgency of this effort, however exceeds the capability of the private sector alone, and will require an accelerated national effort.

Current environmental control capabilities must also be improved by reducing capital and operating costs and preserving overall plant productivity. The importance of this effort is underscored by the fact that approximately 40% of the capital investment and 30% of the total cost of power for new, coal-fired power plants are related to environmental control. This includes sulfur dioxide (SO_2) scrubbing, particulate control, solid waste disposal, water treatment and plant cooling. These controls in their current form have a major impact on plant efficiency and reliability. Closely associated with this issue is the increasing difficulty in siting new utility and other energy facilities

Since its inception, EPRI has worked with the Department of Energy (DOE and its predecessor agencies), the Environmental Protection Agency, and other Federal agencies with energy research and development responsibilities to achieve mutual technical objectives. In the spirit of that long-standing cooperation, EPRI and others recommend an accelerated national program to better understand the environmental issues constraining the use of coal and to develop, demonstrate and promptly apply improved, clean coal technology. This effort would build on activities already underway within the Federal and private sectors. The Clean Coal Technology Initiative and the resulting November 1984 DOE solicitation for opportunities in emerging clean coal technologies is responsive to this recommendation.

The Role of Coal

Coal is by far our most abundant domestic fossil fuel resource and has been the cornerstone of the national goal to achieve increased energy self-sufficiency under each of the last four administrations. The imperative for coal has grown rapidly over this period as the reliability and security of our petroleum supply has become more uncertain and the nuclear power initiative has been increasingly delayed. Today 75% of the 900 million tons of coal produced annually in the United States provides about 60% of our electricity. This growing interdependence of coal and electricity reflects the unique opportunity that electricity provides to transform coal into a versatile, broadly available, energy form.

Despite its abundance, coal has never been the most desirable fossil fuel form. It contains less energy per unit mass than natural gas or oil, it is cumbersome to transport and it has created a variety of environmental issues. As a result environmental requirements have joined cost reduction as the primary consideration in the design and operation of coal-fired power plants and are the driving forces pushing coal utilization technology in new directions.

Conflicting perceptions about the effectiveness of clean air programs, which have already produced a 33% reduction in emissions, have driven the emission control debate for the last several years. In essence the debate has been reduced to an argument over which sources should be forced to further control SO_2 emissions, by what means, and at whose expense. With the growing understanding of the complex interaction among pollutants, the strict SO_2 focus no longer seems as relevant. Instead, the nation should be concentrating on developing an effective, sustained strategy to maintain and continue the substantial progress which has been made in all aspects of emission control. An important element is vigorous application of the new coal utilization technologies which combine emission control with the combustion or conversion process.

The utility industry has been a leader in this effort and as a result, there is a very high likelihood of using coal cleanly in every respect this century through joint private/Federal acceleration of the clean coal technology commercialization effort.

Current Limitations

Through one generating technology or another, coal must play a larger role in meeting the gnerating needs for the rest of the century and beyond. But the ways in which utilities are able to use coal will have important impacts on their ability to install needed capacity, on the price of electricity and on the environment.

Conventional pulverized coal units today are the only available technology that has been proven for the generation of large amounts of electriity. In the circumstances now facing the industry, these conventional coal nits with their Federally mandated flue gas scrubber have major disadvantages. Because these units are characterized by economies of scale, they are relativelky large units requiring long construction periods and large capital investments. (A typical new 1000 MW power plant will cost over $1.3 billion). About 40% of this investment will be for environmental control. Licensing and construction may take eight years or more.

The most technically and economically visible element of environmental control on today's pulverized coal-fired power plants is the flue gas desulfurization system or "scrubber." Wet scrubbing is a simple concept, but in practice is complex and expensive. An alkaline reagent, usually lime or limestone, is mixed with water to form a slurry and then sprayed into the flue gas produced by the coal combustion process. The sulfur oxides present in the flue gas are absorbed in the slurry, and calcium sulfite and/calcium sulfate (gypsum) precipitates out for disposal or use. Alternate, but more expensive, options can transform the absorbed sulfur oxides into sulfuric acid or elemental sulfur.

This technology has been defined by the U.S. Environmental Protection Agency (EPA) as the "Best Available Control Technology" for the required control of sulfur oxide emissions. It has been effectively required on all new pulverized coal-fired power plants since 1977. As a result, the U.S. electric utility industry is today operating 119 of these wet scrubber systems on over 50,000 MW of coal-fired boilers. Unfortunately, scrubbers have proven to be among the most costly and least reliable pieces of equipment in the utility industry.

In a new power plant, the scrubber will commonly cost $140 to $175/kW. In an application to an existing plant it typically costs 10-40% more, but this premium may be as high as 100%. High cost derives from more than design and construction. Scrubbers yield large volumes of wet waste requiring extensive land areas for ponds or landfills, for example, about one square mile a foot deep for each year of operation by a 1000 MW power plant burning 3% sulfur coal. This is a significant environmental side effect of today's flue gas desulfurization systems. Scrubbing also uses huge amounts of water (1000-3000 gal/min), and these processes still often have problems with plugging and fouling of equipment and corrosion of fans and ductwork downstream, matters that add to operating cost and reduce power plant reliability. Finally, scrubbers extract a penalty of 3-8% of plant output energy, simply to run pumps, fans, and flue gas reheat systems, and maintenance costs are two to twenty times that of the rest of the power plant.

Some years ago, Federal leadership for the development of improved flue gas cleaning systems was transferred to the DOE. This was applauded as a progressive step promoting resolution of the technical problems limiting the effectiveness of Federally mandated control technology. Unfortunately, very little Federal participation has been achieved, although many opportunities exist. The effectiveness of government participation will depend on a much more aggressive R&D policy which focusses on the key problems and jointly commits to the major technology projects required for their resolution. By comparison, EPRI alone is investing annually more than four times the current DOE effort in flue gas cleaning technology.

The Need for New Technology

From the time of Thomas Edison's first electric generating station in 1880 to the 1960s, the pace of coal-fired power plant technology advancement continued at a remarkable rate. Efficiency increased eight fold while power plant size increased by a factor of 20,000 over this period. Power plant costs dropped in corresponding fashion. Over the past 20 years, however, further progress has stagnated in the face of a variety of new constraints including escalating capital cost, declining construction productivity, new environmental control requirements, declining coal quality, and licensing delays. As a result, it costs three times more today, in constant dollars, to install a kilowatt of coal-fired electric generating capacity than in 1967 and even more than in 1920. This, in turn, is reflected in rising electricity rates. In short, the fruits of technical progress achieved in the 50 years prior to 1967 have been lost in the past 17.

Based on these changing realities, only a fundamental improvement in coal-fired power plant technology can effectively respond to the growing constraints on coal-fired power generation and restore economic progress in electricity production.

As a result, the electric utility industry stands today at a threshold of change in its technological base for coal-fired power generation. Successful new technology must satisfy two basic and interconnected requirements.

a. Reduced Cost and Risk This requires modular power plants that can be rapidly constructed over a range of sizes to better match demand growth, and can utilize a wide range of coal quality in a single design.

b. Improved Environmental Control. This requires technology that can meet existing and emerging environmental requirements while minimizing the need for expensive, inefficient "band-aid" control hardware such as scrubbers.

An accelerated, two-pronged approach to achieve this transition is necessary: First, promptly transfer improved coal technology from development to application and second, extract the last measure of performance from the existing electricity generating base to span this transition period. Coping with this transition will require an immediate and intensive commitment over the next five years on the part of the utility industry, its suppliers and government if we are to assure electricity supply and control cost while protecting the environment.

The urgency of this joint commitment is underscored by the challenge to the nation's electricity supply capability over the remainder of the century. For example, the electricity generating capacity currently installed or assured of construction completion will only support an average growth rate in electricity demand of less than one percent per year over the remainder of the century. By comparison, electricity demand over the turbulent past 12 years increased an average of 2.3% per year. This period saw two oil-interruptions, dramatic escalation in energy costs, resulting economic recessions, and major efforts in energy conservation.

Based on this recent experience, we can expect electricity demand to continue to pace economic growth. Satisfying even modest growth over the remainder of the century will require a balanced strategy involving additional improvements in conservation and end use management, greater productivity from existing generation capacity (reliability and life extension), plus new generation capacity. Assuming such a balanced strategy can be implemented, the nation will still require 100,000 to 200,000 MW of additional new capacity this century, essentially all of which must depend on coal. New clean coal technology now under development could reduce the cost of this capacity by 30% to 50%. Time is of the essence, however, if this improvement is to be realized in time.

A particular element at risk in this overall strategy is life extension for existing plants. Despite the problems that aging units present, utilities are often finding it less costly to refurbish existing units than replace them with new capacity. As a result, 115,000 MW of existing capacity is expected to be more than 40 years old by the end of the century. This important generation component would be reduced drastically, however, if utilities were required to add flue gas scrubbers and other costly emissions control equipment to those units. In that event, the number of retirements would increase sharply because of the cost and the fact that in some cases the additional equipment could not be physically accommodated. This would correspondingly increase the requirement for new capacity.

By comparison, essentially no new electricity generating capacity has been committed over the last several years and very little additional is planned for commitment over the next five years. This reluctance to invest in new power plants reflects their rapidly escalating cost and the lack of risk compensating incentives for regulated utility investment. The result has been a virtual elimination of capacity additions from the industry's generation planning process for the 1990s. Unless prompt action is taken to reduce the present disincentives to capacity addition, including reducing the risks of demonstrating and introducing new, less costly and more environmentally effective technology, it is probable that inadequate electricity capacity will result this century.

Technology Options

The inefficiencies and cost of current flue gas scrubbing technology coupled with the uncertain possibility that existing plants may require retrofitting of further emission control leads to the need for new, simplified emission control options. These range from improved physical coal cleaning, to low NO_x combustion, furnace sorbent injection and dry scrubbing. No one of these options will satisfy the widely varying conditions over the range of existing coal-fired utility and industrial power plants. As a set, however, they can substantially reduce the cost and productivity limitations of emission control today.

Selection will depend on a number of variables including control requirements, cost and functional criteria such as plant design and space limitations. This third category can be a particularly important constraint when considering retrofit to existing plants. Unlike new plants where the boiler and emission controls can be designed as an integrated unit, retrofit requires adaptation to a plant not designed for such modification. This can lead to compromise and additional expense.

The more effective approach is the use of new coal utilization technologies such as fluidized bed combustion (FBC) or gasification combined cycle (GCC). These technologies combined emission control within the combustion or conversion process. The result is both greater emission control efficiency and improved generation productivity to fundamentally resolve conflicts between energy and the environment. This underscores the value of economic and regulatory incentives that encourage prompt transition to these improved coal utilization options.

The principal appeal of these technologies is that they directly address the major factors affecting coal-fired power generation - notably, cost and emission control. Combining emission control with the combustion or conversion process is inherently less costly, less energy-intensive and more efficient than removing pollutants from the flue gas. As a result, they are a more effective use of national resources than additions of flue gas desulfurization systems to current coal-fired capacity.

Figures 1a and 1b compare the short duration and relatively limited control capability of retrofit control requirements with the much greater potential of these new clean coal technologies. For example, proposed acid rain control legislation that would retrofit flue gas scrubbers on up to 100,000 MW of existing, high sulfur coal-fired generating capacity would cost the nation $200 billion over the remaining life of the affected plants. A more effective alternative would be introduction of new, clean coal technologies that offer greater emission control efficiency and improved generation productivity. If the $200 billion necessary to implement the scrubber retrofit strategy were instead invested on plants using advanced coal technologies, it would provide about half of the new generating capacity the nation is likely to require over the next 30 years. Such an investment in advanced clean coal technology would at the same time provide superior environmental control, not only for sulfur oxides but for nitrogen oxides and solid waste as well, while also improving the productivity and cost of power generation.

The most effective national coal utilization program therefore should have four major objectives. Based on the existing development foundation, all four objectives can be achieved within the next five years. It will require, however, a major, joint private/Federal effort to share the costs and risks, particularly at the technology demonstration scale.

a. Establish a sounder scientific base to guide the nation on the needs and appropriate timing of emission controls.

b. Demonstrate the array of potentially more effective retrofittable emission control alternatives to current flue gas desulfurization (scrubber) technology.

c. Demonstrate the advanced coal utilization technologies, e.g. atmospheric fluidized bed combustion, pressurized fluidized bed combustion, and gasification combined-cycle, over a sufficient range of conditions to establish performance, cost, and reliability.

d. Establish incentives to encourage the prompt commercial implementation of these technologies.

In order to meet these objectives, the utility industry, its suppliers, and EPRI, have therefore jointly proposed over $2 billion in joint demonstration projects to DOE. Only 38% of the required funding would be Federally provided. These are in response to the November, 1984 DOE program announcement on emerging clean coal technologies.

These proposed projects are remarkably consistent in scope and cost estimate with the independent recommendations of the DOE's Energy Research Advisory Board (ERAB) Panel on Clean Coal Use Technologies which encourages expanded DOE participation in coal technology development and demonstration. These projects reflect both the broad scope of opportunities to expand improved coal utilization and the major investment which the utility industry and its suppliers are prepared to make in developing and demonstrating these improvements. Table 1 and the Attachment describe these opportunities in more detail.

The EPRI Contribution

For EPRI this means accelerating our already substantial R&D effort in environmental assessment, clean coal technology, and as a management focus for utility coal utilization projects. For example, EPRI funding for clean coal resarch development and demonstration during the period 1985-1989 will encompass the following effort:

	1985-1989 EPRI Expenditures (Million$)
Environmental Assessment	78
Power Plant Performance Improvement	41
Coal Quality	43
Emission & Effluent Treatment	129
Fluidized Bed Combustion	127
Coal Conversion	164
	582

This represents one-third of the Institute's planned budget over the next five years and is in addition to the over $500 million already spent by EPRI on these R&D programs. The breadth of this program reflects the great diversity among utilities in their generating mix, environmental requirements, fuel availability and cost. No single technology can satisfy all situations. A flexible selection of clean coal options is essential to a healthy and responsive electric utility industry in the1990s and beyond. Over half this total will be directed to technology demonstration projects.

EPRI has been pleased to be both a partner and a catalyst over the past decade to accelerate the commercialization of clean coal technology. An important question which must be resolved before large scale application of these options can proceed is proof of their long term reliability under utility operating conditions. The EPRI program, therefore, stesses the demonstration of these options at sufficiently large scale to verify their commercial reliability. In the case of the atmospheric fluid bed combustion and coal gasification, joint private/Federal efforts with EPRI have culminated in the necessary commercial demonstrations as indicated by the Cool Water gasification combined cycle project and the three AFBC demonstrations with TVA, Duke Power and the State of Kentucky; Northern States Power; and Colorado-Ute Rural Electric Cooperative. It is the Federal participation with the private sector during development and prototype testing which has helped provide the confidence for these demonstrations to proceed under private sector initiative. In addition, sustained Federal participation in both Cool Water and the TVA AFBC demonstration has been crucial to the prompt implementation of these pioneer clean coal utilization projects.

It is Federal participation as a risk sharing investor in demonstrations initiated and managed by the private sector which has been the key to the successful government/industry partnership in these projects. The success of this approach provides a confident prototype for the necessary continued joint Federal/industry effort in clean coal technology commercialization.

The Clean Coal Technology Reserve provides a mechanism to extend this Federal participation to other deserving clean coal technologies. In its absence opportunities on coal cleaning, pressurized fluidized bed combustion and other combustion improvements as well as environmental control technology will be constrained from application. All of these opportunities can have a fundamental impact on the quantity and quality of coal utilization and electric power generation over the coming years.

Issues Facing the Private Sector

The role of the private sector in carrying out this R&D must consider the unique aspects of the primary using industry-the electric utilities and their technology suppliers:

- The electric utility industry is a financially stressed, regulated industry. Rates of return are regulated and therefore, profits do not necessarily reflect risks to investors.

- Major financial risk is associated with incorporation of innovative technology into an established and complex electric power system that must remain economical and reliable. The task of ensuring that planned capacity additions are sufficient to meet suply has tranditionally been the province of utility management, but the disincentives to investment have forced management to place first priority on delaying commitments to new plant.

- Utility supplier firms are not assured of a sufficient return on R&D investment to maintain technical leadership in the current limited domestic market situation. R&D is only the first step in a project which, if successful, will require time and order-of-magnitude greater expenditures for engineering, manufacturing, marketing and capital before a profit is realized. The possibility of changes in government policies over the period further amplifies the risk.

- Energy tax credits for new technology, permitted by other industries, are not available to electric utilities. This is at a time when the utility industry must assume a growing leadership for the development of its essential technological improvements. Contrary to popular conception, the utility industry is one of the most technologically intensive and it is technology which must solve the difficult demands of the future.

- The producers and users of coal represent highly diversified and decentralized industries. This reality presents a special problem in both the range of technologies necessary to meet the diverse needs and the ability to focus sufficient resources. EPRI has provided a unique capability for a large fraction of the utility industry but it is unable to satisfy the industry's needs under the present regulatory and investment environment.

- Financial problems facing the industry and its inability to generate capital funds for improvement or expansion makes additional R&D funding even more difficult. As a result, EPRI is able to fund less than half the scope of its program at a time when the needs are increasing dramatically. During this period of fundamental change in power generation technology, full recovery of all reasonable R&D expenditures should be allowed.

- Foreign countries, where a more cooperative partnership between government and industry exists, are aggressively moving to assume leadership in the development and commercialization of improved coal utilization technology.

- Loss of technological leadership may force the utility industry and its suppliers to depend on these foreign sources. Other, far-reaching implications for supplier confidence and the U.S. international position are self-evident in such foreign dependence.

Taken together these circumstances continue to pose a problem of major porportions - a problem which should be of national concern. This will only be resolved through a national effort to reduce the risks of a rapid massive technical revitalization in coal technology for power production. Concern for the future adequacy of electricity supply must also be reflected in the regulatory process where the risks of new capacity should be compensated by opportunities for the investor to benefit from successful risk taking.

The issue becomes especially critical when it is necessary to build large scale demonstrations. These are essential elements in proving out the reliability, economics and technical capability of new technologies. It is also often necessary to gain experience with several such large scale projects before the risks are reduced to the level of broad commercual acceptability, especially in he utility industry where reliability of service must take first priority. Thus, there are a number of programs in coal utilization related technology for which the funding mechanism to achieve prompt development and application is not evident. These are necessary to resolve the issues constraining coal use today and for the foreseeable future.

The rate of market penetration of these new coal utiliation options would also be enhanced by the development of regulatory and economic incentives which encourage introduction of innovative technology. Particularly important is the development of a quantitative basis for environmental regulation, plus incentives to offset any operational uncertainties associated with new power generation technology. These economic incentives could include making exempt, pollution control bonds available for any clean coal utilization technology. Other economic instruments encouraging the use of such processes might include accelerated depreciation treatment and enhanced tax credits or bond guarantees.

The Federal Role

The Federal government can play an important role in fostering the early introduction of new technologies that can be applied to meet the needs of clean, coal-fired, power generation this century. Unfortunately, Federal programs are not giving sufficient emphasis to that objective. Indeed, the trend in Federal spending has been toward long range R&D projects whose potential benefits lie in the more distant future while turning away from the early commercialization of promising technologies.

The best criterion for the distribution of Federal R&D funds will be the "Marketplace"; i.e., the willingness for private sector cofunding, particularly cofunding by the technology user. The Appendix discusses a number of these "marketplace" opportunities which are proposed by the private sector. In this time of budget stringency, every expenditure should be put to a severe test of cost effectiveness. All promising areas cannot be pursued and priorities must be set. In this context the private sector should also be more involved in the priority-setting process.

The total amount budgeted by DOE for FY 1986 in the field of Clean Use of Coal, is about $57 million. This is about half the corresponding commitment by EPRI alone. This continuing budget decline is inconsistent with the needs which the increasing use of coal implies. Within the Clean Use of Coal area, the overall DOE program is only able to touch on most relevant technical areas. Most critically, the budget does not allow DOE to aid in the transfer of the new technologies to the private sector nor to assure their prompt commercialization. Specifically, as recommended by DOE's ERAB Clean Coal Use Technology Panel, the Federal government should participate in the needed demonstrations which are characteristic for utility acceptance of new technology and which are necessary to respond to government policies and regulations. This recommendation also reflects the diversufied and decentralized nature of the coal using and producing industries and the resulting range of technology options required plus the limitations in focusing sufficient private sector resources.

An example of the impact of the current lack of Federal partici pation in private sector technology demonstration and commercialization initiatives is particularly evident in the Pressurized Fluidized Bed Combustion development program. Major progress has been made over the past several years in converting this techology from an engineering possibility to an important electric power producing technology having the lowest busbar energy cost potential of any near term coal utilization option. The effective cancellation of Federal support on the brink of successful proof of concept is indeed "seizing defeat from the jaws of victory."

The Federal government has a unique opportunity to work closely with the private sector to resolve the various constraints, often resulting from other government actions, on the nation's ability to make use of coal. Obviously, careful selection of projects and extensive private cofunding are prerequisites. The Federal role should be patterned after the successful experience in the Cool Water and TVA AFBC demonstrations where its participation was as a risk sharing investor in privately initiated and managed demonstrations with a clear commercialization objective.

This approach would also improve stability of support and purpose for cofunded projects. A prime concern of private sector R&D management is that program direction and budget, once adopted, will not be changed arbitrarily. This is particularly important to multi-year demonstration projects where change in direction is costly and wasteful. This improved stability would facilitate commercialization of improved coal technology.

Conclusions

The nation stands at a threshold of fundamental change in its technological base for coal-fired power generation. The present commercial technology is nearing the end of its development potential and is increasingly hard pressed to respond to the rapidly changing requirements being placed on the industry. An accelerated, two-pronged approach is necessary: first, promptly transfer improved coal technology from development to application and second, extract the last measure of performance from the existing generation base necessary to span this transition period. Coping with this transition will require an intensive, joint commitment over the next 5 to 10 years on the part of industry and government.

The actions of the Federal government in direct support of energy related research, development and demonstration, and in the form of incentives, have a profound effect on the private sector's ability to develop and utilize clean coal technology. Federal programs need to consider the underlying circumstances affecting private industry and the importance of electric energy and coal to the nation's economy and security needs. The rate of commercialization and use of improved technology also depends on legislative and regulatory incentives. Too often our dependence on the adversarial approach makes the uncertainties and conflicts restricting coal use more severe and disruptive than necessary and restricts the introduction of technological improvements.

There is no shortage of opportunities to improve the efficiency, reliabiity and environmental performance of emerging clean coal technologies. We are learning how to produce power cleanly from coal in a varity of forms meeting the demands of the diverse national energy system. The question is whether we can reduce this knowledge to practice in a period when both regulatory uncertainty and financial disincentives constrain the effort.

The future is now, and success depends on prompt aggressive action by government and industry. The problem affects all phases of the development cycle, but is greatest in the financially-intensive large pilot and demonstration steps necessary for commercial confidence. The Clean Coal Technology Reserve to provide federal participation in private sector demonstration initiatives can substantially enhance the nation's ability to commercialize the many developments in clean coal technology. EPRI is prepared to do its part in formulating and implementing these efforts, including the investment of $580 million over the next five years alone.

Table 1

PROPOSED CLEAN COAL DEMONSTRATIONS WITH EPRI PARTICIPATION
(Million $)

	Technology Demonstration	Total Funding	Recommended Federal Participation
A.	Coal Quality		
	1. Intensive sulfur and ash separation	40	20
	2. Efficient Fine Coal Cleaning & Recovery - EPRI CCTF	60	15
	3. K - Fuel Cleaning and Pelletizing	39	10
	4. Biological Coal Desulfurization	20	10
	5. Automated Coal Cleaning Plant Process Control	20	10
B.	Combustion Technology		
	1. Coal-Water Slurry	50	20
	2. Furnace Sorbent Injection for SO_2 Control (LIMB)	60	25
	3. Low NO_x Combustion	25	10
	4. Combustion Diagnostics and Coal Variability Impact Reduction	50	25
C.	Flue Gas Cleanup		
	1. Southern Company/Chiyoda 121 Process	40	10
	2. EPRI High Sulfur Coal Test Center	35	5
	3. Regenerable NO_x/SO_x Control	27	13
	4. Baghouse Sorbent Injection for SO_2 Control	25	5
D.	Pressurized Fluidized Bed Combustion		

1. Turbocharged PFB Boiler	90	45	
2. PFB Combined Cycle	120	60	
3. Circulating PFB Prototype	70	40	
E. Atmospheric Fluidized Bed Combuston			
1. NSP Conversion	56	5	
2. Colorado-Ute Circulating AFB	117	30	
3. 100 MW Coal Refuse Combustor	125	30	
F. Integrated Gasification Combined Cycle			
1. Slagging Gasifier & Advanced Turbine IGCC	440	180	
2. IGCC Methanol & Electricity Production	40	20	
G. Fuel Cell - Coal Gasification			
1. Phosphoric Acid Fuel Cell	50	20	
2. Carbonate Fuel Cell	150	90	
H. Environmental Assessment			
1. Impact Mitigation	20	5	
2. Atmospheric Tracer Demonstration	200	40	
Total	1969	743	(388)

Figure 1A

ANNUAL UTILITY SO_2 EMISSIONS
3% Peak Growth

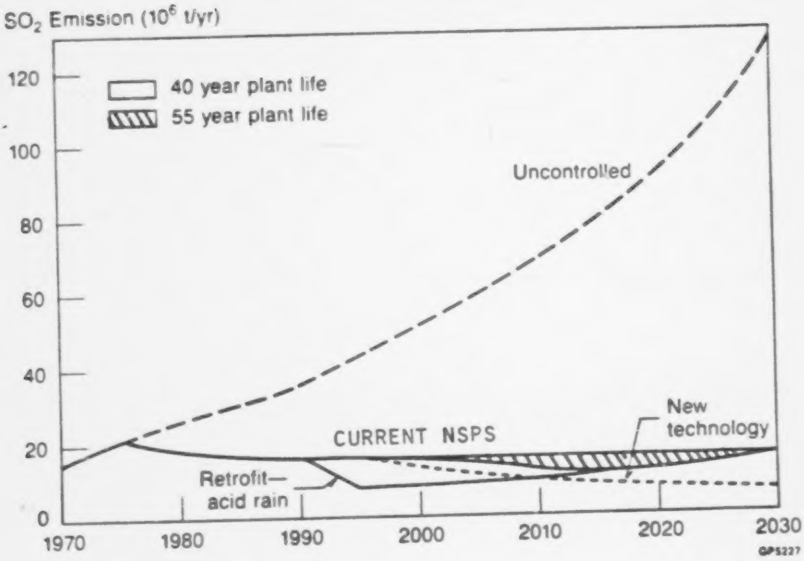
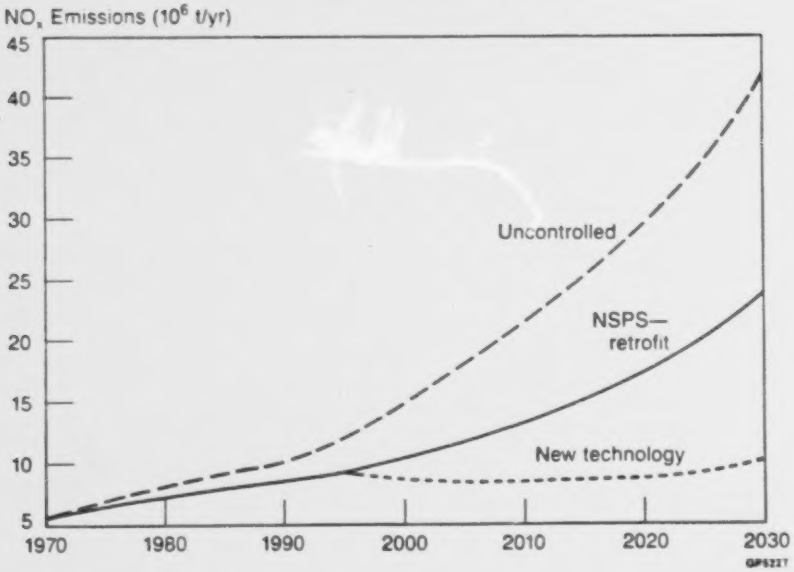


Figure 1B

ANNUAL UTILITY NO_x EMISSIONS
40-Yr Plant Life; 3% Peak Growth



Attachment

EMERGING CLEAN COAL TECHNOLOGIES
ENGINEERING DEMONSTRATION PROGRAM

The need for this program is great because of the nation's very limited current ability to transfer potentially superior coal utilization technology into commercial application. The present lack of an adequate funding mechanism to build the facilities necessary to demonstrate the reliability, economics and performance of new coal technology is a source of national concern. While private sector efforts have been maintained, they are insufficient in the face of declining Federal participation and in the absence of corresponding incentives for additional private investment. As a result, there are a number of programs in direct coal combustion where the funding to achieve prompt demonstration and commercialization is not evident. This may have profound consequences for the 1990's when new electric generating demands, which must rely on coal, collide with the growing environmental ethic of our society. Specific technologies requiring an accelerated Federal and private sector initiative include:

1. Coal Quality Improvement

   a. Coal Cleaning

      Coal quality is central to the efficiency, reliability and environmental performance of coal combustion. Coal cleaning was once a method restricted to high value industrial processes such as steelmaking. More recently, physical cleaning has come to be applied broadly for steam coal as a means of reducing fuel transportation costs, improving plant reliability and reducing emissions.

      Today, essentially all commercial coal cleaning relies on physical separation methods. These methods are applied in varying degrees today to over 50% of the high-sulfur steam coal used by the utility industry. This application has been primarily for economic reasons. First, to reduce transportation and waste disposal costs and second, to reduce operating and maintenance costs in the boiler and coal handling equipment caused by uncombustible impurities, The increasing variability in coal quality and the resulting impact in power plant performance and availability has also led the utility industry to increase its attention to quality control by increased cleaning of its coal feedstock. The third major benefit of coal cleaning is emission reduction.

      Physical coal cleaning is most effective for bituminous coals with high pyritic sulfur content, particularly those mined in north Appalachia and the Illinois Basin where 20% to 30% of the total sulfur content can typically be removed. However, part of this SO_2 emission reduction potential has already been realized in the cleaning done today. For example, over one-half of the sulfur removal potential is already being achieved in the Illinois Basin and about one-third in north Appalachia. On the other hand, physical coal cleaning to remove sulfur is typically ineffective for the low-sulfur southern Appalachian and western coals. As a result, cost effectiveness varies from about $200 per ton of sulfur removed for some Illinois Basin coals (Illinois, Indiana, west Kentucky) to over $2000 per ton of sulfur removed from some low-sulfur coals.

The opportunities to improve sulfur and ash removal through coal cleaning, therefore, vary widely and depend on upgrading existing coal cleaning facilities as well as installation of new plants. The limiting cost factor in physical coal cleaning is the loss of coal during the cleaning process and the effective heating loss from increased moisture content. To achieve its full potential, EPRI and the utility industry are active in the development of improved coal cleaning technology plus characterization of steam coal cleanability and cost. The emphasis is on finer (smaller particle size) coal cleaning and drying techniques to improve coal recovery and thus reduce cost. It is also anticipated that finer cleaning will require even greater R&D emphasis as we try to achieve more ash and pyrite liberation.

This coal cleaning R&D program involves an EPRI commitment of more than $7 million a year plus significant cofunding by individual utilities, and others. A focal point for this program is the EPRI Coal Cleaning Test Facility (CCTF) located near Homer City, Pennysivania, and operating since 1981. Built entirely with private funds at a cost of $14 million, this is the newest and most advanced facility of its type. Based on commercial equipment, the CCTF is demonstration scale with a maximum coal handling rate of 20 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can accommodate a variety of projects resulting from EPRI research as well as others in the coal R&D community. Other objectives include operator training and development of a coal cleaning data base for the utility industry.

There is also substantial uncertainty concerning the performance and utilization of existing coal cleaning facilities. As a result, accurate determination of the opportunities to use excess capacity in existing cleaning plants and upgrade their sulfur removal capacity is difficult. Because of the heterogenous nature of coal, the cleanability and associated cost and benefits can vary widely. For the high-sulfur north Appalachian and Illinois Basin coal producing regions typical costs are indicated in Table A-1.

In some cases, further savings in addition to transportation and waste disposal may also be achieved through improved boiler reliability and reduced maintenance. Much remains to be done, however, in correlating these effects on a site specific basis. On the other hand, it should also be noted that the large majority of coal cleaning is accomplished by the coal producer, at or near the mine. As a result, the actual price premium associated with cleaned coal may be substantially higher than the actual cost of cleaning, depending on the market factors existing at the time.

Unfortunately under the limitations of most of the proposed acid deposition legislation, it is unlikely that this SO_2 reduction potential of coal cleaning will be realized. SO_2 reduction requirements of 50% or more and/or very low emission limits exceed the cleanability potential of coals currently burned in the affected region. Alternatively, the relatively small quantity of low-sulfur coal used has an inherently low sulfur removal potential. As a result, it is unlikely, unless more compliance flexibility is encouraged, that additional SO_2 reduction through expanded coal cleaning will exceed 0.5 MMTPY although the potential exists for 1.5 MMTPY or more of additional SO_2 reduction.

As a first priority, additional resources should be directed to increasing the scope of the joint DOE/EPRI advanced coal cleaning development project which will use the CCTF to test various advanced physical and chemical cleaning processes. These additional resources would both accelerate the availability of results and assure large scale testing of a broader range of cleaning processes. Additional priority coal quality objectives should also include:

- Improved sampling and analytical procedures to insure confidence in coal reserve quantity and quality estimates.
- Techniques for improving the slagging and fouling characteristics of lower rank coals.
- More economical chemical cleaning techniques prividing thorough sulfur and ash removal.
- Development of physical coal cleaning methods as a part of advanced coal utulization technology such as coal gasification and coal-water slurries.

TABLE A-1

TYPICAL HIGH SULFUR COAL CLEANING COSTS

	New Intensive Cleaning Plant*	Upgrade Plant To Intensive Cleaning Capability*
Capital cost ($/KW)	45	20
Levelized Cost ($/MBtu)	0.30-0.45	0.14-0.17
Cost per ton clean coal	($) 7 - 10	3 - 4
Cost per ton SO_2 removed	($) 400 - 800	500 - 800

*1000 tons/hr capacity, 1983$, 30 year levelized cost basis, capacity factor 40%, availability 80%, high sulfur North Appalachian and Illinois Basin coal.

- Automated cleaning process control and on-line continuous measurement techniques to improve reliability and produce quality.

- More efficient and economical fine coal cleaning and recovery techniques.

2. Combustion Control

a. Combustion Diagnostics and Effects on Power Plant Performance.

Areas requiring additional effort include:

- Characterization of coal ash chemistry and its effect on combustion.

- Standardization of slagging indices.

- Effect of coal particle size on fouling/slagging.

- Effect of coal variability on power plant performance.

Achievement of these objectives, which may be further accentuated if coal cleaning and switching are increased to meet emission control requirements, will first require expanded combustion testing facilities. These should include a 100 million Btu/hr facility whose results could be directly extropolated to commercial scale furnaces and boilers. It is also essential that smaller facilities be instrumented to measure the transient chemical and physical parameters throughout the combustion process as well as the properties of the resulting gaseous and particulate products. This capability could, for example, apply state-of-the-art measurement techniques developed with DOE support at the Sandia Combustion Facility. It might be most effectively implemented in conjunction with a stable university research program to achieve much needed national centers of excellence in coal science.

b. NO_x Combustion Control

Historically, combustion modifications have been the commercially available means of controlling NO_x emissions at coal-fired utility boilers. For reasons of cost effectiveness and reliability, combustion controls offering significant NO_x reductions are also likely to continue to be the preferred NO_x control approach for both new and retrofit applications. In general, it appears that the most viable near-term and cost-effective retrofit combustion control options are low excess air firing, overfire air and low-NO_x burners.

Among these options, low NO_x burners have the greatest potential and are receiving substantial development attention here and abroad. Although each boiler manufacturer currently offers a distinctive low-NO_x burner design, there is one common goal. Specifically, these burners are designed to control the mixing and stoichiometry of fuel and air in the near-burner region of the furnace to retard conversion of fuel bound nitrogen to NO_x while still maintaining high combustion efficiency. This is accomplished by controlling the momentum, direction and quantity of fuel and air streams at the burner throat as they are injected into the furnace chamber.

Low-NO_x burners are a relatively attractive retrofit control alternative for a number of reasons. These include:

(1) The existing burner would generally be modified or replaced without involving the expense of new major furnace components (such as ductwork, control dampers and new furnace wall openings necessary for overfire air systems).

(2) NO_x reductions of up to 50 to 60% (300-400 PPM) can be anticipated -- i.e. greater than the reductions achievable with low excess air or overfire air ports.

(3) In some cases, installation of low-NO_x burners may lead to improved combustion efficiency or furnace operation, especially where existing burners are deteriorated or of outmoded design.

(4) Low-NO_x burners may provide the necessary conditions for application of furnace limestone injection to control SO_2. The result may be potentially simple and relatively lower cost, combined SO_2/NO_x control system for existing coal-fired boilers.

While it appears that many coal-fired utility boilers could be retrofitted with low-NO_x burners by relatively straightforward replacement of existing burners, the different flame shape encountered with low-NO_x burners and the specific geometrical and mechanical requirements can represent significant changes from existing equipment. The boiler engineering/operational impacts would need to be addressed on a site specific basis.

Advanced NO_x combustion control concepts are also being developed to more closely control the fuel/air mixing, temperature, and combustion chemistry in the furnace. Alternative fuel-rich/air-rich burner configurations and fuel staging concepts have been developed to separate and control the various combustion zones. Much of this initial development work has taken place in Japan. "Reburning" or overfiring techniques pioneered in Japan are under development to destroy NO_x formed in other furnace regions. Reburning has been reported to produce a 50% further reduction beyond that of low-NO_x burners. Other combustion staging concepts have also emerged. For example, EPRI has sponsored the development of a primary combustion furnace concept with Babcock & Wilcox and is currently sponsoring several retrofit development programs with the boiler manufacturers. EPA is also developing the distributed mixing low-NO_x burner that is expected to be demonstrated on a full scale boiler.

c. Furnace Sorbent Injection

One of the most publicized "new" technologies under development for reducing SO_2 emissions is furnace sorbent injection, also known as LIMB. Attempts to apply this process date from the 1960's, but because the process chemistry was not well understood, SO_2 removal efficiency was poor. The potentially exorbitant costs of retrofit scrubbing, however, have led to a renewed examination of limestone injection by industry and EPA. Applicability limits will probably be determined by degree of upper furnace mixing, unit size, back pass heat transfer surface geometry, and system economics as affected by age and capacity factor. SO_2 control capability appears limited to about 50% for high-sulfur coal.

There are also a number of issues that must be resolved before commercial commitment to furnace sorbent injection technology can be confidently considered. The major issues identified by both U.S. and West German developers regarding utility boiler retrofit applications are:

(1) Effects on furnace slagging and fouling which degrade boiler availability and efficiency.

(2) Uncertainty in scaling up laboratory SO_2 removal and process design data to full scale boilers. For example, it now appears preferable to have sorbent injection in the upper furnace separate from NO_x control modifications. In addition, ash composition has been shown to have a major impact on SO_2 removal efficiency.

(3) Need for particulate control upgrading because of a 200% to 300% increase in fly ash loading and altered ash electrical properties.

(4) Ash disposal constraints. Limestone injection could substantially increase the total quantities for disposal.

The goals of the various research programs, therefore are similar but the specific research approaches are quite different, although complementary. In the U.S. development is principally supported by EPA and EPRI. To date research has focused on laboratory programs to both acquire the necessary process data and to evaluate power plant impacts prior to committing to commercial scale demonstrations.

Because of the developmental status of the technology, no actual process cost data are available. However, retrofit cost estimates have been made for furnace limestone injection based on standard EPRI economic premises. The results indicate a probable capital cost in the range of $40 to $100/kW, including particulate control system upgrading and a total levelized cost of 6 to 12 mills/kWh for high-sulfur coal. This does not include the cost of any reduced boiler performance or increased maintenance resulting from application of this technology. This again is based on a SO_2 removal efficiency of 50% which leads to a cost per ton of SO_2 removed in the range of $650 to $1000. Thus the relatively low SO_2 removal efficiency and high limestone requirement may tend to offset the capital cost advantage.

Retrofit demonstrations of in-boiler sulfur control technology should be emphasized as a relatively low cost, near-term approach to reducing SO_2 emissions from existing boilers. The research projects conducted to date have laid the groundwork for prototype tests at a number of utility boilers in the 50-150 MWe size range. These prototype tests are an integral part of the development process and are necessary to provide confidence for commercial application. The issue here is the impact on the performance and reliability of the boiler and particulate control system, not just SO_2 removal efficiency.

At least seven utility companies are interested in participating in this prototype effort, including financial support and hosting the tests. We estimate that four prototypes will be necessary to qualify the limestone injection technology over the range of desired boilers and coal conditions. Only one is proceeding today at Ohio Edison with EPA support.

Unfortunately the development of this technology is limited by the lack of funding necessary to implement these planned prototypes. Less than half the approximately $60 million necessary to develop and demonstrate this technology over the next few years is budgeted by the Federal and private sectors.

d. Coal-Water Slurry

The retrofit of an oil-fired boiler or at least 100 MWe using clean coal is a valuable objective and should focus on the use of coal-water slurry (CWS) in a boiler originally designed for oil. The slurrying of deeply cleaned coal aids the cleaning process and enhances its handling and storability in the fuel system associated with oil-fired plants. Eighteen utilities are now participating with EPRI in the engineering evaluation of alternative sites for such a demonstration. Such a demonstration could be performed by 1986, if sufficient CWS production capacity can be established. A demonstration in the 400 MWe size range would be particularly advantageous if price guarantees or other support to achieve CWS production of about 1 million tons per year can be provided. To assure the technical foundation of such a large scale CWS application, further R&D attention should also be given to:

- Development of more reliability CWS burners
- Development of erosion resistent convection pass tubing materials.

This would logically complement EPRI and DOE efforts involving slurry characterization, development of utilization guidelines, and testing of slurry handling, pumping and firing equipment. From a regulatory standpoint, it is essential that boilers converting to deeply cleaned coal in any form be permitted to meet their existing emission requirements and not be forced to meet New Source Performance Standards (NSPS). Otherwise, commercial acceptance will be minimal.

Flue Gas Cleaning

a. Flue Gas Desulfurization

Today, flue gas cleaning for SO_2 control depends on scrubbers using primarily a slurry of lime or limestone and water. Because of its high SO_2 control efficiency relative to other available options (up to 90%), the emphasis on scrubbers rapidly increases as control requirements become more stringent. Unfortunately, scrubbers are complex chemical engineering facilities which are expensive and difficult to apply options for existing plants. They also have a major impact on reliability and efficiency and create undesirable environmental side effects. As of December, 1984 the electric utility industry had 119 scrubbers in operation and an additional 101 under construction or planned as mandated by the Clean Air Act. This represents a present commitment to scrubbers of over 110,000 MW, greater than the rest of the world combined.

This commitment also represents the largest single cost element in the environmental investment for a new coal-fired power plant. This investment is typically 20% or more of the total cost of the plant. The $175/kW or more capital cost of FGD on a new plant is exceeded only by the cost of the boiler itself. Maintenance cost for the FGD system is two to twenty times the maintenance cost for the rest of the power plant. As a result, the National Research Council in its 1980 report on FGD technology recommended that highest priority be given to improving the reliability of FGD systems for application to high sulfur coal. Although average FGD availability on medium and high sulfur coal has increased from 53% in 1978 to 85% in 1982, this is still not consistent with utility requirements and represents a substantial loss in available electric generating capacity.

The EPRI R&D program to improve this unacceptable FGD performance is the largest of its type in the country with $50 million invested to date and an equivalent amount planned for the next five years. It emphasizes failure cause analysis, improvements in process chemistry, materials of construction, water and energy use, hardware design, plus performance data collection and interpretation. In addition, EPRI is actively pursuing the development of improved FGD designs capable of reducing byproduct production and substantially improving cost and reliability.

The levelized cost of retrofit FGD installations may typically rival the present busbar cost of the electricity produced by the power plant. This is especially influenced by the remaining life of these plants. Previous cost estimates of acidic deposition control strategies have typically underestimated these retrofit FGD costs.

These known problems with FGD systems make them an expensive and difficult option for retrofit to existing plants. In our judgement they represent a band-aid solution, often creating as many problems today as they solve and should be replaced by more effective technology as rapidly as possible. Adding them to older plants is generally uneconomic and should be avoided except in cases where the risk to the ecosystem is found to be unacceptably large and no other alternative is available. Typical retrofit planning values for both limestone scrubber and lime spray dryer FGD systems on a 500 MW power generating unit burning 2.5% sulfur content coal with a 60% capacity factor and 15 years remaining life are listed in Table A-2.

The highest priority should be placed on resolving the reliability, byproduct disposal and cost issues impeding the effectiveness of flue gas desulfurization (FGD), especially for retrofit on existing coal-fired power plants. A variety of simplified and improved FGD processes have been developed by the private sector, such as the Chiyoda 121 Process, which should be demonstrated at the 100-150 MWe scale as soon as possible. The effort should not, however, be limited to processes capable of 90% SO_2 removal. Simplified processes with somewhat lower removal efficiencies may be very useful in the event that retrofit control requirements develop.

Federal participation is also encouraged in the New EPRI High Sulfur Test Center being built to address the chemistry and materials issues limiting FGD performance and reliability. This could have, for example, a substantial impact on any acid rain control strategy requiring retrofittable FGD. The Center will consist of a series of scrubber pilot plants with supporting laboratories all operating on high sulfur flue gas produced by a coal-fired utility boiler. EPRI and the utility industry have committed $12 million for the construction of this facility with an additional $25 million for operating costs.

The inclusion of a demonstration of a combined SO_x/NO_x removal system within the next five years is speculative. Although DOE is today supporting development of several such technologies including the Sulf-X and E-Beam processes, these are still at relatively small scale and a preliminary stage of development. They are unlikely to achieve sufficient performance or cost confidence within the near future tojustify large prototype facilities. Increased funding for smaller pilot scale development would probably be more effective within this time frame.

TABLE A-2

TYPICAL HIGH SULFUR COAL SCRUBBING COSTS

	Limestone Scrubber (1983$)	Lime Spray Dryer
Capital Cost	230 $/kW	190 $/kW*
- Total Levelized Cost	20 mills/kWh(1)	21 mills/kWh(1)
- Energy Use	3-5% of plant input	1-2% of plant input
- Land Use (fixed landfill)	240 acre-ft/yr(2)	250 acre-ft/yr(2)
- Solid Waste	220,000 TPY(2)	240,000 TPY(2)
- Water Use	500-2500 GPM	400-600 GPM
FGD Availability	80-90%	80-90%
- Power Plant Reliability Impact	-5%	-5%
- SO_2 Removal Efficiency	80-90%	60-85%
- Cost/Ton SO_2 Removal	1000-1200$(1)	1100-1400$(1)

*Includes Fabric Filter Baghouse

(1) Does not include cost of any lost generating capacity.

(2) Wet disposal may double these quantities.

b. Electrostatic Precipitator Performance Improvement

The retrofit application of in-furnace or certain other flue gas emission control technologies will have a detrimental effect on the performance and reliability of existing electrostatic precipitator (ESP) facilities at these plants. This degradation will result from both the increased particulate loading as well as the effects on fly ash resistivity. adhesivity, and particle size resulting from changes to fly ash and flue gas composition by the retrofitted control process.

It will, therefore, be necessary to upgrade existing ESP technology including development of improved flue gas conditioning additives, pulsed power supplies, on-line performance diagnostic instrumentation and improved fly ash properties prediction methods. This effort should include full scale field evaluation of retrofit effects plus verification of performance improvements. The result will be utility proven techniques for maintaining and upgrading ESP performance and reliability plus guidelines for the operation and maintenance of the upgraded ESP facilities responding to SO_2 and NO_x control requirements.

c. Water and Solids Integration

Little attention has been given to date to secondary pollution questions of air pollution control, notably compliance with Clean Water Act/NPDES and the Resource Conservation and Recovery Act (RCRA). In addition to a very large increase in both solid and liquid waste products created by retrofit control requirements, the composition of these byproducts will also be affected. New approaches will produce byproducts of different characteristics--e.g., more soluble calcium in waste solids from furnace limestone injection than conventional wet limestone scrubbing.

In conjunction with planned EPRI/utility programs, a full scale integrated water treatment and solids management system at one or more existing plants should be constructed and tested. The system should focus on retrofit applications and be designed along with retrofit SO_2 controls. The effort would demonstrate application of retrofittable water quality control technology plus design and operating guidelines for retrofit water and solids systems.

TABLE A-3

Pioneer Utility Fluidized-Bed Combustion Demonstrations

	TVA/Duke	NSP	Colorado-Ute
Location	Paducah, KY	Minneapolis, MN	Nucla, CO
Size, MW (e)	160	125	110
FBC type	bubbling	bubbling	circulating
Scope	add-on boiler	boiler conversion	add-on boiler & T/G
Coal	high S bituminous	low S subbituminous, high S bituminous & municipal refuse	low S, high ash bituminous
Coal feed system	underbed	overbed	in-bed
Dust collector	baghouse	electrostatic precipitator	baghouse
Dispatch schedule	base load some cycling	2-shift, 5-day cycle	base load
Start-ups per year	30	250	<10
Boiler supplier	Combustion Engineering	Foster-Wheeler	Pyropower (Ahlstrom)
Cost	$220 Million	$50 Million	$100 Million
Federal funding	$ 30 Million Provided	$ 5 Million Requested	$ 30 Million Requested

TABLE A-4 (a)

	Wet Limestone FGD Retrofit (1983$)	AFBC Conversion
Net Capacity after conversion	93 MWe	115 MWe
Capital Cost ($/kWe)	$590 (b)	$480
Total Capital Requirement: ($10^6$$)	45	45
Levelized Cost (mills kWH):		
- Capital	22	22
- O&M (c)	22	25
- Derating (d)	3	(-33)
- Fuel	-7	2
Total	40	16
SO_2 Removal Efficiency	90%	90%

(a) Based on Northern States Power Co. experience.

(b) Includes wet limestone FGD retrofit at $390/kWe, and $200/kWe, for plant refurbishment.

(c) Total fixed and variable O&M for power plant and emission control.

(d) Consists of both a capacity and replacement power charge. Replacement capacity provided by combustion turbine at $270/kWe and fuel at $5/MBtu.

4. Fluidized Bed Combustion

a. Atmospheric Fluidized Bed Combustion

Development of Atmospheric Fluidized Bed Combustion (AFB) has successfully progressed from the process confirmation stage to engineering prototype, making commercial scale utility application possible this decade.

AFB has become an important boiler alternative because it is an evolutionary improvement in coal utilization, better meeting the requirements of the 1990's. The capabilities which excite this interest include: (a) less sensitivity to fuel quality, thus permitting users to operate more in a "buyers" fuel market; (b) ability to control SO_2 and NO_x within the combustion process; and (c) less cost sensitivity to unit size.

This provides the technical basis for 100-200 MW commercial demonstrations by the utility industry which will be operational this decade. Three such complementary utility demonstrations are now being implemented with $350 million in private sector funding at TVA, Northern States Power, and the Colorado Ute Electric Cooperative. These are described further in Table A-3.

In each case the utility industry will fund the largest share of these demonstrations with EPRI and the suppliers sharing the first-of-a-kind risk costs.

As a retrofit AFB project, Northern States Power is converting and repowering an existing coal-fired boiler at the Black Dog Power Station to AFBC as a more cost-effective approach than scrubbing. the conversion is scheduled to begin operation in 1986.

Table A-4compares such an AFB conversion with the alternative of an FGD retrofit. This comparison is based on modifying a 25 year old unit burning 3% sulfur coal with a capacity factor of 40% and having a gross capacity before conversion of 85 MWe. Modification is also intended to extend life to a nominal 50 years.

Although AFB is proceeding favorably into commercial application, considerable opportunity for continued development exists. Rather than concentrating on the investigation of advanced, proprietary AFB concepts, this support should be directed to resolution of the generic materials, fuel characterization and environmental control considerations with pace its application.

In addition, special emphasis should be placed on the demonstration of circulating AFB in both industrial and utility applications.

The continuity and success of the combined Federal/private development effort is making these pioneer AFB demonstrations possible primarily through private support. This provides a successful prototype for similar utility and government collaboration in other areas of coal utilization R&D.

b. Pressurized Fluidized Bed Combustion

The new and dynamic utility climate also influences pressurized fluidized bed combustion (PFB) development. The influence results from the trend toward smaller new unit size plus utility priority on uprating the capacity of existing units to bring generation on line quickly and at the lowest cost. These advantages can translate into an effective reduction in capital costs of $200/kW to $300/kW by better matching load growth and reducing the cost of work in progress (CWIP). PFB provides the opportunity to add these advantages to the inherent fuel flexibility and environmental control capabilities of atmospheric fluidized bed combustion.

As a result, development and demonstration emphasis should be placed on PFB turbocharged boilers which can provide shop-fabricated, barge transportable, steam generation modules. These may be rapidly field-erected to provide the desired uprating in unit sizes of 50 MWe to 250 MWe. This approach can also use coal to replace or increase the capacity of existing oil-or gas-fired plants while meeting stringent siting and environmental control constraints. It also provides the lowest busbar energy cost of any coal-fired power generation option now under development. The primary physical difference between the turbocharged boiler and the PFB-combined cycle that has been previously emphasized is the reduction in gas turbine operating temperature. This substantially reduces the development risk and cost, and improves the reliability of the boiler system.

By developing PFB in this low-risk configuration and demonstrating its feasibility in financially attractive repowering applications, sufficient confidence can be gained to increase the firing temperature in future plants to combined-cycle conditions. This evolutionary path can eventually lead to the 40% + efficient, direct coal-fired, combined-cycle power plant.

The development effort today centers on the PFB boiler and involves the design base for the heat transfer tube bundle within the bed as well as coal feeding, ash handling, and control of the PFB boiler system. The only available facilities for resolution of these technical issues are the International Energy Agency (IEA) Grimethorpe PFB Pilot Facility and Supporting Coal Utilitization Research Laboratory (CURL) in England. Unfortunately the just constructed Curtiss-Wright Wood-Ridge, New Jersey PFB pilot has been terminated by DOE before having the opportunity to operate. Tests at Grimethorpe are planned with two U.S. manufacturers, Babcock & Wilcox and Foster Wheeler. In both cases, the manufacturers will design and supply heat transfer tube bundles for performance and reliability testing. EPRI is committing $5 million to these tests and strongly encourages at least a similar level of DOE participation. These tests are a key stepping stone to implementing planned PFB demonstration projects with the utility industry. As a result of approximately a decade of federally funded research, PFB technology has not reached the proof-of-concept state of development where its advantages can be confirmed. Unfortunately, as this critical R&D threshold is reached, DOE support has been essentially terminated, thus stalling PFB's potential for commercial application in the U.S.

A new joint DOE/private initiative should therefore be mounted which consists of four primary elements: (a) supporting research on fluidization, materials and sorbent performance, (b) proof-of-concept testing at the Grimethorpe and Curtiss-Wright facilities, (c) pilot scale development of circulating PFB, and (d) demonstrations of 100 MW PFB modules for both bubbling and circulating boiler designs. Such demonstrations, estimated to cost about $100 million each, are technically feasible this decade. The pacing item will be the availability of Federal support for the already planned private sector initiatives by Florida Power & Light, Wisconsin Electric, Public Service Electric & Gas, and American Electric Power.

5. Gasification Combined Cycle (GCC)

Coal gasification integrated with combustion turbne combined cycle power generation is an attractive new technology currently being demonstrated at Southern California Edison's Cool Water site near Daggett, California. This project, the capital cost for which was provided by EPRI and the private sector, employs a 1000 ton/day oxygen blown Texaco water slurry fed entrained gasifier and a currently commercial General Electric Frame 7 gas turbine. The design coal is a Utah bituminous coal and the net plant output is about 100 MW. Synthetic Fuels Corporation (SFC) price supports of up to $120 million are currently provided to offset the operating costs for this first of a kind plant. Performance of this plant to date has exceeded expectations in many areas, particularly with respect to emissions where very low levels of sulfur oxides, nitrogen oxides, and particulates have been achieved.

The Cool Water experience and other EPRI studies show that GCC plants based on this technology can be economically competitive and environmentally superior to other coal technologies. Major advantages are: (a) higher efficiency (b) lower emissions (c) lower water and land requirements. Commercial plants in the 200-500 MW range will comprise multiple trains of similar sized components (gasifiers, gas turbines) already demonstrated at Cool Water. These plants can be installed in phases using modular shop fabricated components, thus enabling utilities to add capacity in a manner that better matches load growth without the extended construction periods and attendant financial exposure experienced with large conventional power plants. The multiple train configuration of such GCC plants should also result in high overall plant availability.

Another attractive opportunity for the introduction of GCC technology into the utility industry is to first install gas turbine or combined cycle capacity based on conventional oil and gas fuels and to add coal gasification later when either (a) base load demand has grown or (b) conventional oil and gas fuel costs have risen unacceptably. This strategy is currently being investigated by EPRI and contractors with ten individual utilities for their specific systems.

EPRI is also planning to support the further development of other competing coal gasification processes such as the British Gas/Lurgi slagging gasifier and the Shell entrained gasifier. A program of test runs on U.S. bituminous coals is currently planned on a 600 ton/day British Gas/Lurgi gasifier in Scotland starting in 1985 under joint funding from EPRI, the Gas Research Institute and the British Gas Corporation.

The British Gas/Lurgi slagging moving bed gasification technology is particularly suited to the use of the abundant high sulfur bituminous Appalachian and Mid Western coals which are currently under utilized. The British Gas/Lurgi moving bed technology differs markedly from the Texaco entrained gasifier used at Cool Water and we believe offers certain advantages in efficiency and oxygen consumption. DOE and EPRI both participated in the earlier stages of development of the British Gas/Lurgi technology and formerly planned to proceed to a "demonstration" plant. Accordingly EPRI believes that the next logical step for GCC technology development would be the demonstration of the British Gas/Lurgi slagging gasifier based on high sulfur Eastern or Mid Western coal. The value of such a project could be markedly enhanced by the inclusion of a high firing temperature, more efficient gas turbine in the plant configuration. Both DOE and EPRI have previously supported considerable prior work with the gas turbine manufacturers on such improvements, which have now advanced to the stage where full scale implementation is justified.

A GCC project based on these technologies and concepts is currently being studied by EPRI, Detroit Edison and Consumers Power. A plant capacity in the 150-200 MW range is contemplated with a total estimated cost of about $400 millon. DOE support of $150 million is being requested for this project.

GCC systems also offer attractive opportunities for the coproduction of other energy forms such as steam, substitute Natural Gas (SNG) and methanol. The coproduction of methanol is of particular interest to utilities since it can provide a source of peaking fuel. the "once through" methanol concept which has been under development with DOE, EPRI and other private support is now ready for a larger scale test at a coal gasification site. The most logical and suitable locaton is at TVA's Ammonia from Coal project in Muscle Shoals, Alabama. Additional DOE support of about $20 million for this facility at TVA is strongly recommended to provide a test center for the above mentioned once through methanol concept at the 125 tons/day capacity.

6. Fuel Cell - Gasification

Fuel cells are modular, environmentally acceptable power units that offer the most efficient use of petroleum and natural gas in the near-term and coal derived fuels in the longer-term.

Phosphoric acid fuel cells are expected to achieve commercial status by 1990. A market potential of 45,000MW is projected for the year 2000 with savings approaching 90 x 10^6 barrels of oil equivalent) per year. The importance of this technology to the electric utility industry is described in separate testimony provided by the Fuel Cell Users Group of the Electric Utility Industry. Further evidence of the importance of phosphoric acid fuel cells to electric utilities is provided by the increased commitments of five Japanese and two U.S. manufacturers to large scale demonstration and commercial prototype projects.

However, the commercial success of phosphoric acid fuel cells is not assured and will depend upon continued technology improvements to achieve the reliability and the capital costs necessary to penetrate the market and achieve the projected benefits. The absence of any funding for phosphoric acid fuel cells in the Department's FY86 budget is alarming and ignores the needs of on-going programs as well as the progress being made under the coordinated support of DOE and EPRI. These efforts if sustained at current levels promise to achieve the targets while improving the power plant efficiency from the current 40% to as much as 47%. Beyond this, the integration of fuel cells with coal gasifiers need to be explored to confirm the projected coal to A.C. power efficiency of 37%. Interest in using phosphoric acid fuel cells with coal was emphasized by the submission of nine proposals in response to DOE's recent program announcements regarding emerging clean coal technologies. EPRI has bedgeted over $50 million to support the continued development and commercial introduction of phosphoric acid fuel cell power plants during the 1985-1989 time period.

EPRI also supports the longer-range molten carbonate and solid oxide fuel cell technologies. We feel that the Department's FY86 request for these technologies is adequate.

7. Advanced Coal Liquefaction

The Wilsonville Advanced Coal Liquefaction Research & Development Faciligy has made a significant contribution to advancing coal liquefaction technology. During 1985, EPRI will provide funds to add approximately $900,000 in capital improvements to the Wilsonville pilot plant. This new equipment will provide for the testing in FY'86 of new process configurations which may further improve the process efficiency, reduce capital cost, and provide a better understanding of this complex process. Current programs which are planned through 1986 would advance this technology to technical readiness for scale-up to commercial application. The Wilsonville program for FY'86 is not expected to produce a "breakthrough" which will allow direct coal liquefaction to compete with the current crude oil price of $25 to $30 per barrel. However, it is expected to produce a data base that can be used to design a two-stage process to produce a given product slate whenever economics or national commitments require. We currently estimate that distillate products would cost $45 to $55 per barrel (in 1984 dollars).

The major objectives can be reached by the end of 1986. Unless there is a drastic change in the nation's outlook for oil, the plans for Wilsonville will include completion of the facility at the end of 1986. $6.5 million in DOE participation in FY'86 is encouraged to permit achievement of these objectives.

The Wilsonville facility has become a unique national asset in that it has the broadest capability of any liquefaction pilot plant in the United States, is open for the testing of proprietary technology developed by others at a meaningful scale, and produces sufficient quantities of products for small-scale combustion testing and product upgrading research. The project has consistently operated within budget.

If the program is ended before the program goals have been completed, the data obtained to date will lose a significant part of their value. Currently the data are in the form of discrete points. These data cannot be used to predict what product slates can be expected from operation at conditions that were not tested. Modeling of individual process units is an essential step before the presently unrelated data can best be understood.

8. Environmental Assessment and Mitigation

Major benefits to coal utilization could be obtained by a substantial experiment in lake liming and a massive tracer investigation of the transport of SO_2.

Environmental Impact Mitigation

In Sweden where a similar situation exists, a major national program is underway to mitigate acidification and introduce a fish stocking program. Currently, about $4 million per year is being spent to manage between 10,000 and 20,000 lakes. However, several questions remain.

Some ecologists are concerned as to possible secondary effects of using lime or limestone in surface waters. In a $3 million three year study entitled Lake Acidification Mitigation Project (LAMP), EPRI has initiated an investigation of the ecological consequence of neutralizing waters in three Adirondack Lakes. Swedish investigators will provide data on a few of the lakes to compare with the EPRI-derived data.

However, no systematic program for analyzing the costs and effectiveness of various mitigation systems has been started. Currently, there are a number of options for delivery of the neutralizing material: by airplane, helicopter, truck, tanker, truck, boat, etc. Also, there are a number of substances which can be used to neutralize the water: lime, quick-lime, limestone, and, there exist a number of ways of delivering the materials: by single treatment in the water, by multiple treatments of the water, by treating the lake itself or by treating streams, the shoreline, or the entire watershed.

While a good deal of data exists from the Swedish experience and a little data from Canadian and U.S. experience, there is a need ror a systematic cost and efficiency assessment of mitigation alternatives in the U.S. A major experiment providing experience on 250-500 lakes could be performed for about $20 million.

Determination of contributions from local and distant sources

If there were a decision to reduce emissions in order to reduce deposition in certain sensitive ecological areas, the current understanding of the atmospheric processes is not sufficiently developed to enable targeted options to be reliably chosen. Whether nearby sources or distant sources are the most important contributors to acidic deposition in the sensitive areas makes a huge difference in the potential cost of a control program.

For example, if distant sources were the major contributor, to achieve a reduced deposition a general reduction in emissions would have to be used. On the other hand, if local sources were more important, a much more limited emissions control program would be possible. In analyses of such possible differences, it has been found that the cost of emissions control might be reduced by as much as a factor of ten if we can get the data needed to design such an efficient program.

EPRI has examined how this atmospheric information might be acquired. Current knowledge of atmospheric physics and chemistry and current modeling capability do not now provide enough information to accurately predict source-receptor relations. Nor do improvements in these areas of science over the next ten years seem likely to provide the accuracy needed.

However, EPA, NOAA, DOE and EPRI have experimented with utilizing tracers to obtain the needed source-receptor information. In addition, EPA has designed a small regional experiment while EPRI has designed an experiemnt to encompass the entire eastern one-half of the U.S. Currently, the identified major difficulties in implementing such an experiment are being studied. An experiment of this type would cost about $200 million and could be initiated in 1986.

Mr. **Boucher**. Thank you, Mr. Mannella.

We will hear from Mr. Webb.

Mr. **Webb**. Thank you very much. I appreciate the opportunity to appear before you today to discuss the Gas Research Institute's views and recommendations on the clean coal technologies initiative established by Congress last year.

It is particularly encouraging that 175 private sector firms responded to the Department of Energy's request for statement of interest. This response is amazing when you consider DOE made it extremely clear in its announcements that no funds were currently available, and furthermore, DOE did not intend to request funds to start any of the proposed projects. The private sector response clearly indicates a need for Federal funding to accelerate research for and demonstration of emerging clean coal technologies. GRI fully supports funding made available to DOE for clean coal technology demonstrations, especially for near-term applications. We are particularly encouraged that some of the applications proposed recognized the use of natural gas in combination with other technologies for flue gas cleanup and, in the longer term, for coal gasification.

GRI is an independent, not-for-profit scientific research organization that manages the cooperative research and development program for the gas industry and its customers. We are not a government contractor; however, we do cofund and coordinate much of our research with DOE, therefore Congress' actions on the DOE budget do have a direct impact on the gas industry's research program.

To summarize briefly, a review of the DOE report to Congress indicated the largest number of industry responses were in four technology areas that could have the most near-term impact. These technologies—flue gas cleanup, surface coal gasification, fluidized bed combustion and coal preparation—are all at the state of development where the next logical step is a field demonstration. Over 60 percent of the private sector respondents, or 70 percent if you include only those that had specific proposals, recommended work in these four areas. I think they should be given a priority in any clean coal initiative.

Also, the DOE report noted that nearly all of the submissions requested direct cost sharing rather than other forms of financial assistance. I think this indicates direct Federal support through cofunding is required to accelerate the commercialization of new clean coal technologies.

The ERAB report emphasized a couple of factors that I think were important in reviewing the role of the Federal Government. One was that the number of coal-use situations is so large and diverse and the specific problems are so site specific that no one technology or solution will solve the problem. This is particularly true for retrofit applications which represent the overwhelming majority of the market.

The ERAB report also noted DOE policy has recently excluded work beyond the proof-of-concept stage. This policy limits timely commercialization of new technologies, and a revision of this policy is recommended.

Another factor to consider in determining the most prudent Federal role is the extent to which the United States must rely on coal to meet its electric power generation demands between now and the year 2010. Under any reasonable scenario of growth, electricity demand through the 1990's will continue to increase and require the construction of new generating plants. I noticed just last week the North American Electric Reliability Council in their annual projection indicated that current projected capacity, including all plants currently planned, can only support a 2.2-percent peak demand growth between now and the year 2000. If historical relationships between GNP growth and electric demand continue, we either will have a stagnant economy with increasing unemployment and the rising misallocations of funding due to that or else we are liable to have a shortage in electric peak capacity in the late 1990's. Therefore, I think it is urgent that we initiate a program for clean coal technologies.

This scenario becomes especially convincing when you consider that the United States holds one quarter of the world's known coal reserves, and electricity use, even with all of the conservation due to higher energy prices and economic downturns, has grown by approximately 30 percent since 1973.

In evaluating the urgency of moving forward with the clean coal technology demonstrations, I think it is informative to recap the action since the Energy Security Act in June 1980. With the Iranian crisis in 1979, the United States was faced, for the second time in 6 years, with skyrocketing crude oil prices. Responding to the need to develop domestic sources of energy, Congress created the Synthetic Fuels Corporation to provide financial assistance to the private sector to undertake commercial synthetic fuels projects. However, at that same time DOE had a large and very aggressive Fossil Fuels Demonstration Program, on the magnitude of $700 million to $1 billion per year. It was assumed the technology developed in these DOE demonstrations would be available for the SFC and the private sector to draw upon for commercial demonstrations. However, today, the DOE Fossil Fuels Demonstration Program has been terminated. The result is a serious technology gap between the long-term generic research and commercialization. Yet, DOE continues to stress research and demonstrations are the role of the private sector, who will be guided by market forces.

I would like to refer you to an ERAB report done in 1982 for DOE on energy R&D priorities. I quote:

> A little over half our primary energy finds its way to consumers through the electric and gas utilities, and these utilities are regulated, price-controlled industries selling their products not at free market prices, but at controlled prices. Both these regulated industries have weak incentives to spend on R&D. If successful, the benefits go to the ratepayer; if unsuccessful, the expenditures may be disallowed as "imprudent."

In this environment, the utility sector simply does not have the incentives to make all of the necessary research investments to adequately demonstrate currently needed clean coal technologies.

One other note in that area on the economic incentives that I think is important for clean coal technologies is mostly in response to Federal laws and regulations. Surely, if the changes in Federal law require new technology, then there is a Federal role—primarily at DOE—in accelerating the demonstration and commercialization of the required technology, especially if it is to bring existing boilers into compliance with changing Federal laws.

Finally, in summary, I think I would like to make one other comment before I make specific recommendations. There was an issue raised this morning on whether it is an investment or a cost in cleaning up our Nation's coal. I believe I am correct that the cost of oil imports in 1984 was approximately $60 billion. I think the Secretary pointed out that this was dollars spent by individuals. That is correct, but it also contributed to the Federal deficit; to the trade balance, which leads to higher interest rates.

Also, I think it should be pointed out that the cost of the program to DOE that Congress is imposing is about $750 million. I would like to point out that the cost of one carrier to defend the Persian Gulf would cost more than the $750 million proposed for this entire program.

Finally, Mr. Chairman, after considering these factors, I would like to recommend the following:

Congress should recognize that DOE has a leading role in demonstrating clean coal technologies and appropriate funds in fiscal year 1986 to initiate a limited number of the proposed demonstrations.

Priorities should be given to the near-term technologies: flue gas cleanup, coal gasification, fluidized bed combustion, and coal preparation. Use of natural gas in the demonstration of flue gas cleanup should be assigned a top priority.

Second, the private partner should be responsible for providing a significant portion of the construction and operating cost. It is important that cofunding by the user of the technology be required.

Third, the executive branch should leave day-to-day management of the project to the industrial partner.

Fourth, in determining which proposals to select, it should be recognized that a stand-alone plant, which usually will be the most expensive type of demonstration, should be considered as a last resort. Priority should be given to proposals that use existing host facilities.

And finally, the Synthetic Fuels Corporation should be encouraged to make provisions in its future financial assistance for commercial synthetic fuel plants to require the capability for testing advanced clean coal technologies at the plantsites in the future; in other words, that they would serve as a host site for these demonstrations, and that would significantly reduce the cost.

In conclusion, the Federal energy research policy has created a technology gap by restricting the DOE role to proof of concept. Congress can take a bold step today toward closing this gap by appropriating funds in fiscal year 1986 for clean coal technology demonstrations to be cofunded with industry.

Mr. Chairman, this completes my testimony. I would like to ask that my complete statement be included in the record. And I would be happy to respond to any questions that you or any members may have at this time.

Mr. BOUCHER. Without objection, the statement will be received.

[The prepared statement of Mr. Webb follows:]

TESTIMONY OF DAVID O. WEBB
VICE PRESIDENT, POLICY AND REGULATORY AFFAIRS
GAS RESEARCH INSTITUTE
BEFORE THE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATION
COMMITTEE ON SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES
MAY 8, 1985

I appreciate the opportunity to appear before you today to discuss the Gas Research Institute's views and recommendations on the clean-coal technologies initiative specified in Section 321 of the Department of the Interior and Related Agencies Appropriations Act for FY 1985 enacted by House Joint Resolution 648, Public Law 98-473. It is particularly encouraging that 175 private-sector firms responded to the Department of Energy's request for statements of interest. This response is amazing when you consider that DOE made it extremely clear in its announcement that no funds are available and, furthermore, that DOE does not intend to request funds to start any of the proposed projects. The private-sector response clearly indicates a need for federal funding to accelerate research for and demonstration of emerging clean-coal technologies. GRI fully supports funding being made available to DOE for clean-coal technology demonstrations, especially for near-term applications that use natural gas in combination with other technologies for flue-gas cleanup and for coal gasification to provide one of the most cost-effective long-term methods to clean up our vast coal resources. In the near-term, the use of gas in a reburn mode for nitrogen oxides (NO_x) reduction and as a transport medium for sorbent injection to reduce sulfur dioxide (SO_2) in coal combustion systems offers the potential for early retrofit in many utility and large industrial boilers. These technologies should be given high priority in any demonstration program.

GRI is an independent, not-for-profit scientific research organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the gas industry and its present and future customers. The R&D program is implemented through contracts with research organizations, engineering, and other professional service firms, universities, energy companies, and manufacturers. Even though GRI is not a government contractor and does not accept federal funds, GRI cofunds and coordinates many of its research programs with DOE. Therefore, Congress's actions on the FY 1986 DOE budget have a direct impact on the gas industry's research program.

A review of the DOE report to Congress, Emerging Clean Coal Technologies dated May 1985 indicates the largest number of responses were in the four technology areas that could have the most near-term impact on allowing the U.S. to utilize its vast coal resources in an environmentally acceptable way. These technologies--flue-gas cleanup, surface coal gasification, fluidized bed combustion, and coal preparation--are all at a state of development where the next logical step is field demonstration. Particularly encouraging to GRI is that two of the technologies--flue-gas cleanup and coal gasification--would use natural gas to clean up our nation's coal. These applications of natural gas have tremendous potential. Since these four technolgies were proposed by over 60 percent of the private-sector firms that responded, their demonstration in cofunded field tests should receive immediate attention and top priority.

Also, the DOE report noted that nearly all of the submissions requested direct cost-sharing rather than other forms of financial assistance. This cost-sharing is necessary due to the significant risks associated with the technologies; the current softening of world oil prices; the inability for many utilities to recover capital costs due to the novelty of the technologies; a lack of evidence that the technologies are practical, useful, and economical; and the need to accelerate the commercialization of the technology through demonstrations so the technologies are available to industry in the early 1990s. These factors convincingly indicate that direct federal support through cofunding is required to accelerate the commercialization of clean-coal technology. Without this federal support, many of these technologies will not be demonstrated. Others eventually will be demonstrated by the private sector but not in time to meet the nation's need for future energy demands.

Another factor emphasized by the draft Energy Research Advisory Board (ERAB) report on clean-coal technologies that must be recognized is that the number of coal-use situations is so large and diverse and the specific problems are so site-specific that no generally applicable technology or solution can be presented. This is particularily true for retrofit applications which represent the overwhelming majority of the market. The draft ERAB report also noted, "DOE policy has recently excluded work beyond the proof-of-concept stage; this policy limits timely commercialization of new technologies, and a revision of this policy is recommended." Therefore, the use of federal funds to cofund the demonstration of multiple technological approaches with industry is the most viable solution to using our coals cleanly.

ROLE OF GAS IN CLEAN COAL TECHNOLOGIES

Federal policy has long overlooked the significant role natural gas can play in helping the nation use coal in an environmentally acceptable manner. Therefore, it is particularly encouraging to GRI and the gas industry that several of the responses to demonstrate flue-gas cleanup include the use of gas for both NO_x control and to assist in SO_2 control. In fact, for near-term and many retrofit applications, gas used in combination with coal combustion systems is probably the best solution.

Natural gas is our nation's cleanest fossil fuel. Its combustion emits virtually no particulates, sulfur oxides, or reactive hydrocarbons, and it produces far lower emissions of nitrogen oxides and carbon monoxide per unit of energy than coal or oil. Used selectively, either alone or with other more polluting fuels, relatively small quantities of natural gas could contribute significantly to protecting our air quality in a least-cost manner. Given the size of the gas resource base and the economics of gas production, the competitive position of gas relative to other environmental control options should remain favorable. In addition, a million-mile pipeline and distribution network is already in place which extends to most potential select gas-use customers. Thus, cost-effective solutions to using coal cleanly are both possible and practical by using natural gas.

Gas can be used in one combustion unit to offset the emissions from dirtier fuels, such as coal, in another unit; it can be used for simultaneous combustion of gas and coal in a single combustor; and it can be used in flue-gas cleanup systems as a transport mechansim for sorbent injection to reduce sulfur oxides (SO_x) and in a reburn mode to reduce NO_x. Therefore, using gas as part of the overall approach to controlling pollutant emissions during coal use should become one element of national energy policy. Additionally, coal gasification is another route, though longer-term, to using our coal in an environmentally acceptable way.

FEDERAL ENERGY R&D FUNDING POLICY SHIFTS

It is important to review the shift in priority this Administration has assigned to energy R&D when examining the need for DOE support for clean-coal technology demonstrations. The dramatic decline in energy R&D funding is very evident when comparing the FY 1981 and 1986 requests after deleting the business-related functions. This decline is easily obscured since the Administration included $2.4 billion of weapons R&D and $685 million of general science activities in the FY 1986 energy R&D budget category. When these non-energy-specific items are removed from the energy R&D budget, in FY 1986 the Administration requested only 20 percent, or a $2.3 billion allocation, for energy R&D programs, while in FY 1981 it requested about 60 percent, or $5.9 billion, for energy R&D.

Another factor limiting technology demonstration and transfer to industry is that DOE has established a general policy of not funding research beyond proof-of-concept. This policy of leaving hardware development solely to industry sounds nice, but it hasn't worked. The result is a technology gap that is widening as DOE continually withdraws to long-term and basic research. The justification for intermediate-range energy applications R&D is as strong as ever. DOE must once again reemphasize energy R&D and establish technology development resulting in hardware projects and demonstrations as a focal point for fossil energy research.

DOE R&D AND DEFENSE PROGRAMS
($ Billions)

	FY 1981	FY 1986
Energy R&D	$ 5.922	$ 2.295
General Sciences	0.523	0.685
Department Management	0.362	0.299
Defense Programs	3.443	8.060
TOTAL	$10.250	$11.269

If national energy policy continues this trend of constant reduction in energy R&D spending and no federal support for technology demonstrations, we will soon find ourselves without technology for full development of our vast domestic fossil fuel resources. The result will clearly be to increase our reliance, once again, on unstable foreign imports.

U.S. FUELS OUTLOOK

Another policy to consider in determining the most prudent federal role in supporting demonstrations of clean-coal technologies is the extent to which the U.S. must rely on coal to meet its electric power generation demands between now and 2010. As a result of several major independent trends, the use of coal in the U.S. is expected to continue to increase at a reasonably steady pace for most of the next 25 years. The two major influences of this trend are the continued high (compared to coal) price of oil and the reduced contribution of nuclear power. Both private and federal forecasts agree that the U.S. will continue to rely on fossil fuels for over 75 percent of its energy supplies during the next 25 years.

Natural gas will continue to maintain an important role in a highly competitive energy mix throughout the remainder of the century. In fact, GRI projections indicate that with development of advanced technology for extracting gas from tight formations there will be sufficient gas supplies at competitive prices to increase annual consumption from today's level of 18 trillion cubic feet per year to approximately 20 trillion cubic feet per year. With development and demonstration of new technology, gas can help meet some of the new electricity demand in the 1990s.

However, unless technology is developed and demonstrated to allow the U.S. to utilize its coal in an environmentally acceptable manner, the U.S. faces the possibility of shortages in electric generating capacity in the 1990s. Recent forecasts by our National Energy Plans have shifted from 4-percent-per-year growth in the economy in the early 1970s to almost no growth forecasted in the mid-1970s to about 2-percent-per-year growth in the early 1980s. At the same time, during the past decade, electricity growth has ranged from an increase of 7 percent per year to negative growth in 1983 for the first time in 40 years. Under any reasonable scenario of growth, electric consumption will increase. As stated by DOE Secretary Herrington in a speech on April 23, "Demand for electric power has continued to show a strong relationship with the growth of our economy." GRI's modeling efforts indicate future electricity growth will be at a rate equal to approximately 85 percent of the rate of growth of the economy. Therefore, unless our economy is totally stagnant with resulting rapid increases in unemployment and misallocation of resources, electricity demand in the 1990s will continue to increase and will require the construction of new generating plants. If nuclear power does not make a quick resurgance to survive as a viable future U.S. energy option, coal is the major domestic energy option with sufficient long-term resources to fuel the majority of these power plants. This scenario becomes especially convincing when you consider that the U.S. holds one-quarter of the world's known coal reserves, and electricity use, even with all of the conservation due to higher energy prices and economic downturns, has grown by approximately 30 percent since 1973.

While the electric utilities and EPRI have done a good job of funding research on options to burn coal cleanly, a clear need exists for a major DOE role in demonstrating clean-coal technologies. The activation of the $750 million clean-coal technology fund to allow DOE to demonstrate clean-coal technologies in partnership with the private sector would be a valuable investment for securing our future energy needs under environmentally safe conditions.

A "TECHNOLOGY GAP"

In evaluating the urgency of moving forward with the clean-coal technology demonstrations, it is informative to briefly recap the actions leading to the Energy Security Act in June 1980. With the Iranian crisis in 1979, the U.S. was faced, for the second time in six years, with skyrocketing crude oil prices. Responding to the need to develop domestic sources of energy, Congress created the Synthetic Fuels Corporation to provide financial assistance to the private sector to undertake synthetic fuels projects. The Energy Security Act authorized up to $88 billion for synthetic fuels development, of which $20 billion was appropriated in 1980 for Phase I.

At the same time, DOE had a large and very aggressive fossil fuels demonstration program. It was assumed that technology developed in these DOE programs would be available for the SFC to draw upon for commercial demonstrations, especially in Phase II. However, today the DOE fossil fuels demonstration program has been terminated, and the SFC is under attack with the possibility of having the financial resources available to assist commercial synfuels projects either severely limited or terminated.

The result is a serious technology gap between long-term generic research and commercialization. DOE's current R&D policy does not fund "process" development or pilot plant activities. However, the process development stage is perhaps the most crucial stage in the development of a new technology. It is during this stage that a good technical idea is turned into a process with commercial potential. The construction and operation of a process development unit (PDU) leading to demonstration of the technology at pilot or pioneer plant scale are both essential steps in advancing technology. Neither step can be skipped. Yet DOE has determined these research activities are the role of the private sector and will be guided by market forces.

However, in some industries, market forces are not sufficient. Many of the markets in which energy is sold are not "free." As the Energy Research Advisory Board (ERAB) noted in its 1982 report to DOE Energy R&D Priorities:

> A little over half our primary energy finds its way to consumers through the electric and gas utilities, and these utilities are regulated, price-controlled industries selling their products not at free market prices, but at controlled prices. Both these regulated industries have weak incentives to spend on R&D. If successful, the benefits go to ratepayers; if unsuccessful, the expenditure may be disallowed as "imprudent." A strong R&D response to price signals requires both motivation and capability. In many cases the capability is simply lacking.

If there is one thing the energy crisis of the past 12 years has taught us, it is that uncertainty is the only certainty. Long-term energy forecasts have proven to be consistently wrong. We cannot make policy assumptions with any confidence regarding the direction of energy demand, production, and prices. The real interest rates are double the historical experience, and the cost of capital for construction is high. Also, it must be recognized that the economics of many emerging clean-coal technologies are driven by the price of world oil, and this price is not based on production costs but is established by a cartel. In other words, the typical utility executive must make major energy decisions in a very unstable and uncertain operating environment.

In this environment, the utility sector simply does not have the incentives to make the necessary research investments to adequately demonstrate urgently needed clean-coal technologies. Therefore, the DOE policy has created a serious technology gap. The use of the clean-coal technology reserve to give DOE the resources to cofund these demonstrations with private industry is needed to close this gap.

Two gas-related technologies that can make a major contribution to using our nation's coal cleanly are coal gasification and gas-enhanced dry sorbent injection and reburn. Both require federal support for field demonstrations to close the "technology gap."

Coal Gasification

The establishment of a commercial coal gasification industry depends not only on the development of technically and economically viable coal conversion processes, but also on the extent to which those processes are compatible with the environment. New technologies are required to meet the nation's increasingly stringent environmental standards. Advanced coal gasification technologies, with the potential for significant technical, economic, and environmental improvements compared to the commercially available technology, have emerged from the extensive R&D programs that have been supported by the federal government, by GRI, and by other organizations.

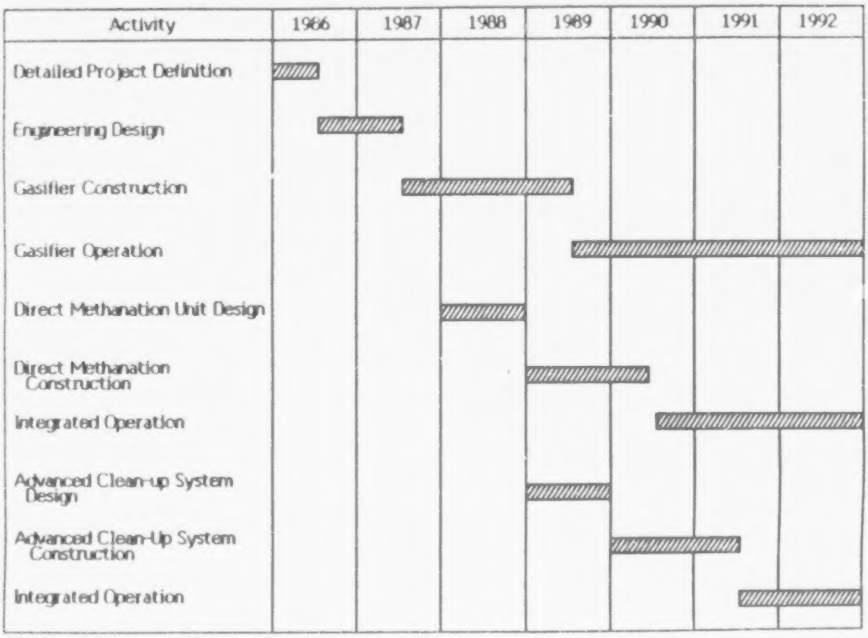
In response to the DOE Office of Fossil Energy solicitation for statements of interest for projects related to development of emerging clean-coal technologies, GRI submitted a proposal for a coal gasification test facility at an existing host site. This project would result in the large-scale validation of advanced coal gasification processes for combined-cycle power applications, for producing pipeline-quality gas from coal, for gas cleanup and methanation, and for testing components and instrumentation.

For these advanced technologies for producing gas from coal (whether for power generation or pipeline-quality gas) to receive adequate consideration as a supplemental energy option, engineering performance data must be available from commercial-size or near-commercial-size systems in the mid-1990s. This will permit the reliable definition of capital requirements and end-product gas costs under conditions where the technical risks associated with the scale-up of the advanced technologies have been reduced to an acceptable level.

GRI is proposing to place a commercial-size or near-commercial-size advanced coal gasification process in an industrial environment where existing supporting systems and utilities are available and where the gasifier products could be utilized in the industrial operation. The gasifier should be oxygen-blown and operate at a pressure of 450 psi to 500 psi in order to provide data relevant to gas production. The program should be structured to accommodate the integrated slip-stream testing of the advanced downstream processing components that would be used to upgrade the gasifier products to a pipeline quality gas.

In 1984, at the request of the Congress, the U.S. Department of Energy conducted a preliminary study to examine the feasibility of installing and operating a semi-works, fluid-bed gasifier at the Great Plains Coal Gasification plant. The study was prompted by the recognition of the need to develop engineering data at a large scale for the advanced gasification technology that was under development in the U.S. and the existence of a large coal gasification plant infrastructure that could help defray the costs associated with developing the required system performance data. In addition to providing detailed technical data on gasifier operation and environmental interactions, substantial experience would be gained in operating commercial-size units based on the fluid-bed, ash-agglomerating technology.

Project Schedule: Large Scale Demonstration- Emerging SNG Technology



The DOE study concluded that the concept of continuing the development of advanced fluid-bed coal gasification technology at the semi-works (600- to 1,000-tons-per-day) scale at the Great Plains coal gasification plant was feasible and had merit. The attitudes of the owners and all levels of management at the Great Plains facility were very supportive of the concept and the use of the facility for such purposes. The developers of the gasifier technologies that might be candidates for continued development at the semi-works scale at the gasification facility also supported this approach to advanced gasifier technology development.

The study considered a test program that would be more comprehensive than just an advanced gasifier activity and would provide for the testing of additional gas processing components. Such components could include advanced downstream processing systems designed for the production of pipeline-quality gas and systems for integration with advanced electric power generation systems, i.e., hot gas cleanup, combustion turbines, etc.).

It is estimated that the design and construction of a 1,000-ton-per-day unit, and the necessary modifications to the existing facility would cost approximately $80 million and would have attendant annual operating costs of approximately $12 million. Assuming six years of operation, the total project cost would be about $150 million. A government/industry 50-50 cofunded project is appropriate at this time because short- and mid-term uncertainties of energy supply make it impossible to identify sufficient short-term incentives that justify capital expenditures for technologies where technical risks have not been demonstrated to be low.

No current commercial system has been satisfactorily demonstrated for high-sulfur caking coals, which are predominantly found in the eastern parts of the U.S. Some advanced concepts, however, have emerged from the extensive R&D efforts and appear to offer the potential for significant improvements over the technology that is commercially available for converting eastern coal to gas. These improvements are in the form of increased flexibility, lower capital costs, lower operating costs, reduced end-product gas costs, and reduced environmental impacts.

GRI's proposed coal gasification gas test facility project has the following principal objectives:

1. To demonstrate that the emerging coal gasification technologies have direct application to the production of pipeline-quality gas from eastern coal and offer significant technical, environmental, and economic advantages over the commercially available state-of-the-art technology.
2. To validate the performance characteristics of the emerging coal gasification technologies at a scale that will provide the heat balance, material balance, environmental data, and operational data needed to develop reliable cost estimates for future coal-to-gas plants based on these technologies.
3. To demonstrate the integrated performance of advanced gasifier technology and advanced downstream processing technology such that commercial systems could be constructed to maximize the technical, economic, and environmental advantages of these technologies.

Federal cofunding of this advanced coal gasification test facility with the private sector through the use of funds from the clean-coal technology reserve would be a cost-effective and prudent investment in the U.S. energy future. This should be assigned a high priority in any clean-coal technology program.

Gas-Enhanced Dry Sorbent Injection and Reburn

Concern over acid precipitation and anticipated acid deposition legislation has created an incentive for government and industry to develop more cost-effective technologies to control both sulfur and nitrogen oxides from coal and oil combustion, particularly utility and large industrial boilers. To accelerate the development of flue-gas cleanup technology and to demonstrate the use of gas for both reburn technology to reduce NOx and sorbent injection technology to reduce SOx, GRI recommends that DOE give top priority to cofunding a project demonstrating those approaches as part of the clean-coal technology initiative.

The tests should be conducted in a boiler situated in the Midwest to provide easy access to all eastern coal-producing states. The tests would be based on:

1. Pollutant emissions (absolute reduction of NO_x and SO_x)

2. Impact on boiler performance and operability.

3. Cost of the technology (dollars/ton of pollutants removed).

4. Tolerance to boiler design and coal variations.

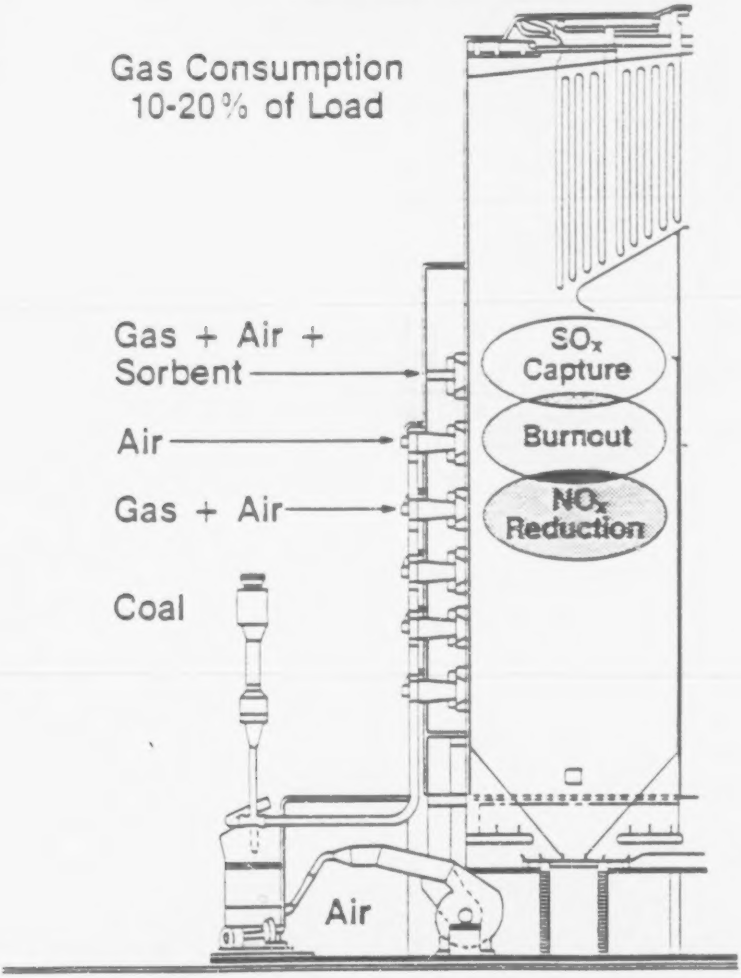
GRI and the U.S. Environmental Protection Agency are currently cofunding the Energy and Environmental Research Corporation (EERC) of Irvine, California, to develop dry sorbent injection technology combined with combustion modification techniques to control SO_x and NO_x emissions from coal and oil combustion. GRI's portion of this study is to examine control of NO_x and SO_x emissions from coal combustion by incorporating two developing gas combustion technologies which can be applied individually or as an integrated system.

1. Reburn Technology. Use of natural gas as a reburning fuel to reduce NO_x emissions.

2. Sorbent Injection Technology. Use of natural gas to generate more reactive and higher capture efficiency of sorbents for enhanced SO_x reduction.

The EPA and other research groups within the government and the private sector are investigating methods to enhance the cost-effectiveness of sorbent injection technologies, e.g., limestone injection multistate burner (LIMB), for SO_x and NO_x control from coal and oil combustion systems. EPA has provided $860,000 ($400,000 in FY 1983 and $460,000 in FY 1984) in coordinated funding for the project via their existing reburn/sorbent injection contract with EERC. GRI's project ($937,900), which began in April 1984, expands EPA's original focus on coal-fired reburning/sorbent injection at EERC to include an evaluation of the additional benefits (e.g., cost reduction, increased emissions control, etc.) obtainable from the use of gas.

GAS APPLICATIONS RESEARCH


Gas Consumption
10-20% of Load
Gas + Air + Sorbent
Air
Gas + Air
Coal
Air
SO$_x$ Capture
Burnout
NO$_x$ Reduction

Gas Enhanced Dry Sorbent Injection
Plus Gas Reburn –
SO$_x$/NO$_x$ – Control

Sulfur oxides can be controlled by removing sulfur from the fuel or sulfur oxides from the products of combustion. However, current methods such as scrubbers or coal cleaning generally are capital intensive with high operating and maintenance costs or do not provide the necessary degree of SO_x control. One of the more promising SO_x control strategies is to inject calcium based sorbents into the combustion chamber and capture the sulfur prior to the boiler outlet. This process was investigated in the late 1960s and was abandoned because it could not achieve the desired SO_x control and also tended to create operational problems. Recently, there has been sufficient incentive to re-examine the limestone injection process (e.g., LIMB) as a cost-effective alternative that could approach FGD sulfur removal at a lower cost. The EPA's efforts in recent years have focused on the development of this technology for coal-fired boilers. GRI's program with EERC is to enhance the cost-effectiveness of this technology through the use of gas combustion technology. Gas may offer significant sorbent injection performance benefits because it can be used to more effectively control the conditions at which limestone sorbent is calcined and mixed with the coal or oil combustion flue gases; it can avoid coal-ash/sorbent interaction problems that decrease sorbent surface area; and it can be used more effectively to optimize the temperature profile of the sulfation zone where sulfur capture occurs.

Nitrogen oxide emissions are also considered, although historically to a lesser extent, as a contributing factor to acid deposition. The attention to NO_x as an acid deposition processor is increasing as scientific evidence tends to indicate that both SO_x and NO_x are contributors. The formation of NO_x during the combustion of fossil fuels can be minimized by appropriate modification of the combustion mixing process.

Recently, the Japanese have been exploring a new NO_x control strategy which involves in-furnace NO_x reduction by downstream injection of fuel. EPA is currently conducting research programs to evaluate the potential of this technique for application to U.S. boilers. The term "reburning" has been coined in the U.S. to refer to this process. Where using gas as the reburn fuel, it is believed that this technology is capable of reducing NO_x by approximately 50 to 60 percent beyond the current NSPS level achievable with low NO_x burners. The use of coal or oil as a reburning fuel may introduce operational problems because of poor carbon burnout resulting in a loss of efficiency as well as slagging in the platens or primary superheater region. The specific technical benefits of using gas as the reburning fuel are that gas can be applied without the combustion problems associated with coal-firing in upper boiler regions; gas allows lower exhaust NO_x emission levels to be achieved since it is nitrogen-free; and gas avoids the presence of molten ash in the superheater boiler region, thereby minimizing slagging and fouling problems.

The use of gas technologies could also have an application in those instances where oil-fired boilers are being converted to coal/water slurry mixtures. Combustion systems which burn coal water slurries efficiently in boilers designed for oil rely upon efficient fuel air mixing, precisely those conditions which promote the formation of nitrogen oxides. Consequently, any conversion could result in a considerable increase in both SO_x and NO_x emissions. An additional problem associated with conversion to coal-water slurries is the need to derate the unit to prevent excessive erosion in the convective sections. Natural gas used as a reburning fuel with or without sorbent injection can help solve two problems--pollutant emissions and unit derating.

Potential benefits of gas use are both environmental and economic. The development of more cost-effective SO_x, NO_x and combined SO_x/NO_x control technologies using gas would lower energy costs and improve air quality. The economic benefits are broad-based and provide an alternative to high-cost flue-gas scrubbing technologies and increased ability to use the nation's natural resources along with a decreased dependency on imported oil. The environmental benefits would accrue by significantly reducing the quantity of pollutants emitted by coal or oil burning.

In conclusion, gas has the unique advantage of allowing the simultaneous application of reburn and sorbent injection technologies in the same boiler. Over the next five years, GRI plans to spend approximately $5 million to $6 million to support research and development of the reburn/sorbent injection technology for application to industrial and utility boilers. By using natural gas to enhance reburn/sorbent injection technology, GRI's goal is to increase the NO_x/SO_x capture performance of this technology to NO_x levels lower than attainable with low-NO_x burners and to attain SO_x levels approaching that of wet scrubbing but at a significantly lower cost. Different technology variations are being explored at both bench and pilot scales. The next step is to initiate full scale testing of reburn technology starting in 1986. This testing should be performed using an industrial boiler to demonstrate retrofit applications.

Multiple field tests of reburn/sorbent injection technology are required as application techniques are likely to vary significantly with boiler type (cyclone, pulverized coal, stoker, etc.) It is estimated that field testing of these two technologies will require an investment of approximately $25 million to $30 million dollars over the next five to seven years. Government participation to demonstrate the use of gas in reburn/sorbent injection technology development as a central element of the clean-coal initiative is needed to provide incentives to the utility industry via mitigation of the financial risks.

RECOMMENDATIONS

As a result of reviewing the DOE report, the draft ERAB report, and the current status of coal gasification and gas reburn and sorbent injection technology, I recommend the following:

1. Congress must recognize that DOE has a leading role in demonstrating new clean-coal technologies. There is a clear need for the federal government to continue the natural progression of development for a new technology from the laboratory and proof-of-concept state through the technology demonstration phase.

2. Congress should appropriate funds in FY 1986 to initiate a limited number of the proposed clean-coal technology demonstrations. Priority should be given to the four technologies proposed in over 60 percent of the responses--flue-gas cleanup, coal gasification, fluidized bed combustion, and coal preparation. Use of natural gas in the demonstration of flue-gas cleanup should be assigned a top priority.

3. The private partner should be responsible for providing a significant portion of the construction and operation costs of the facility. By

requiring the industrial partner to bear a substantial risk, the government can expect the private partner to utilize its full capabilites in designing, constructing, and operating a successful facility. It only makes sense, then, for the private partner to be responsible for selecting the process, site, size, energy source, management, and end product for the project.

4. The executive branch should leave the day-to-day management of the project to the industrial partner. The Energy Security Act incorporated a sound philosophy on the role of the SFC program managers in joint ventures that should be adopted by DOE in any demonstration program. Participation is "limited to financial participation only and shall not include any direct role in the construction or operation of the module." Even in the case of direct funding by the SFC, the Act makes it clear that "In no event . . . shall the persons in the joint venture agreement be denied the primary responsibilty for management of the joint venture."

5. In determining which proposals to select, it should be recognized that a stand-alone plant will usually be the most expensive type of technology demonstration and, therefore, should only be considered as a last resort. Priority should be given to proposals that use existing sites.

6. The SFC should be encouraged to make provisions in its financial assistance program for commercial synfuels plants to require the capability for testing advanced technologies at the plant site in the future.

CONCLUSION

In conclusion, the current federal energy research policy has created a "technology gap" for fossil fuels research by restricting the DOE role to proof-of-concept research. There is a need for a viable federal role in the applied and engineering research phases of coal conversion and utilization processes. Congress can take a bold step toward closing this "gap" by appropriating funds in FY 1986 for clean-coal technology demonstrations to be cofunded with industry. Without this federal support, the timely development of advanced processes to use the nation's vast coal resources in an environmentally acceptable manner will be seriously delayed. A joint DOE/industry program is needed now.

Mr. Chairman, this completes my testimony. I will be happy to respond to any questions.

Mr. **Boucher**. I thank both of the witnesses for their thoughtful testimony this morning.

As you may have heard previously, Secretary Vaughan reported on the conclusions of the Department of Energy with respect to whether or not there should be a Government role in helping to finance the demonstration-scale phase of these emerging coal technologies. And his conclusion is that the Government should not, based upon his conclusion, apparently, that these technologies will be commercialized on their own. That private industry will carry the freight on that, and that there is no appropriate role for the Government for that reason.

Now, I gather from your testimony that you disagree with that conclusion. Why is Secretary Vaughan wrong in that? What can you tell us that would lead us to conclude that these technologies will not be commercialized absent a significant Government role?

Mr. **Mannella**. Mr. Chairman, let me answer part of that at any rate. I think that the difference comes in the interpretation of the time frame in which they are needed. With regard to many of the technologies that EPRI is investigating and discussing one could say that in the long run ultimately they probably would be demonstrated by the private sector. The problem that we have is that the generating capacity will be needed by the year 2000, or before the year 2000. And if you look at a calendar and you begin to work backwards. Considering the length of time it takes to bring this generating capacity on line, you begin to see that there is a window now and for the next year or two. If one could move out, demonstrate these technologies, operate the plants for the requisite 2 or 3 years it would take to build the confidence to decisionmakers to go ahead and make those decisions, construction might then begin in the early 1990's and that generating capacity would be available in the mid to late 1990's.

Absent that we will have the situation that my colleague, Mr. Webb, described so graphically, shortages and perhaps stifling of the economy. So, it is a matter of the interpretation of the timeframe in which it is needed that I think is the basis of difference of opinion.

Mr. **Boucher**. That being the case, what is your recommended level for funding for the clean coal technology reserve in fiscal year 1986? $750 million is authorized. Obviously that total amount could not be expended in 1 fiscal year; at least in the first. What is your recommended funding level for the next year?

Mr. **Mannella**. Well, I would feel a lot more comfortable in answering that if I had seen all of the submissions and the imputed values that they suggest. I think that in addressing the question of the amount we have to bear a couple of things in mind. When the Federal Government signs a contract with anybody for goods or services, by definition it is spent at that point. Now, it is true the contractor has not spent it. There is an account set up in the Treasury, and as vouchers come in as work is performed that amount is drawn down.

So, in answering the question I would say that I would be surprised, if, within the totality of the 175 submissions totaling $8 billion, as Mr. Vaughan indicated this morning, that one could not find 200 million dollars' worth of work to begin. And that if you take them in order of priority, you don't start small and work big as you go down the list. Quite the reverse; you start big and go small as you work down the list of priorities.

Mr. BOUCHER. Mr. Webb, do you care to comment?

Mr. WEBB. I would just add one thing. I think what I would do is, if it were my decision to make, say, OK, let's concentrate on the near-term technologies. That ought to be the initial thrust. Authorize, not actual outlays, authorize somewhere approximately a third of the clean coal reserve over the next 2 years. Because I don't think they can get the mechanics going such that you could get all of it in place.

Additionally, I would say give priority to those proposals that come in and are going to do the demonstration at an existing facility, so as much as possible of the capital and construction costs can be eliminated.

And finally, give a preference to co-funding, particularly if the cofunder is the user, not the industrial firm that will capture some of the economic rent. The electric utilities, per se, like EPRI represents come in a user class. They are not going to make any profit off the technology if they can get it out there. They serve their members and, in turn, the citizens of this country.

So that is the way I would approach it. I would say put about a third of it available for authorization over the next 2 years, focus on the near-term technologies, go out with the RFP's, get the responses back, evaluate them against some set of criteria, and make some awards and let's get started.

Mr. BOUCHER. The suggestion was made, and I think there is general agreement, that to the extent that we have a program there should be a selection based in large measure on market forces in terms of the Government's role in funding projects. One criterion to look at, obviously, is the percentage of private industry investment that would be applied to a particular project.

Would you agree that that should be the primary criterion, and should there be other criteria that should be looked at as well?

Mr. WEBB. If I may respond, I think it should be at least one of the two major criteria. I think the second one ought to be, as Eric Reichl stated, the data base behind the technology proposed. Because a fellow could come in and propose 50 percent co-funding in a technology that truly can't have any impact before the year 2000 and has a data base so small that the risk of it ever being successfully implemented by a conservative investment like the utility sector of something around 10 percent. That is not a good investment of taxpayers' money.

So I think you need both criterion, but cofunding certainly is at least as important as any other one.

Mr. BOUCHER. Mr. Mannella, would you care to comment?

Mr. MANNELLA. Well, I agree with what Mr. Webb said and what Mr. Reichl said earlier. I think that we would like to add a good measure of evaluation of the particular technology and the role to which it fits, the broad spectrum of, in our case, utility applications. I think one has to weigh the technology that is, say, ideally suited for new baseload versus retrofit versus when it can be used for both. Inasmuch as there are a significant number of utilities out there representing very different geographical and economic considerations I think that evaluation of the technology and the extent to which it fits would be an important criterion that we would like to focus on.

Mr. **Boucher**. Thank you. My time has expired.

Mr. Packard.

Mr. **Packard**. Thank you, Mr. Chairman.

Do either of you gentlemen have any information as to what our present coal consumption is in this country?

Mr. **Mannella**. Somewhere in the neighborhood of 600 million tons a year I believe.

Mr. **Packard**. I believe that one of the previous witnesses indicated that it could conceivably in the early part of the 1990's reach over a billion tons. Do you agree with that?

Mr. **Mannella**. I really don't have any basis for agreeing or disagreeing. I do recall a number of years ago when there was interest in increasing the use of coal that there was talk about a billion tons per year as sort of an upper limit.

Mr. **Packard**. And I would have to assume that that is if we find technology to clean it up.

Mr. **Mannella**. I would say that is correct.

Mr. **Packard**. What kind of a savings would that bring to the industry?

Mr. **Mannella**. Well, compared to what? Compared to the use of oil?

Mr. **Packard**. Well, I would assume that much of that increase will replace other energy sources.

Mr. **Mannella**. Well, that certainly could happen, Mr. Packard, but I think that Mr. Reichl touched on a very interesting point in his presentation this morning. And that is that we have the overall problem of using coal cleanly in existing and in a new capacity that would come onstream for national health effects and concerns.

Mr. **Packard**. So your general feeling is that the increased use of coal, if we can find the technology that can clean it up, would be to accommodate additional industry and use, rather than replace existing oil and gas usage?

Mr. **Mannella**. I think there would be some of that as well. I think it would serve a number of different needs.

Mr. **Packard**. It would appear to me, particularly in light of your statement, that 80 to 90 percent of the coal use will be in producing electricity and that we would probably see utilities replacing existing sources of energy—gas, oil—with coal. In your judgment, do you think that is a true statement?

Mr. **Mannella**. Well, a lot of that has already happened, and more of it certainly will as the technologies become available.

Mr. **Packard**. In your sixth statement, Mr. Mannella, "environmental concerns cast a cloud over the degree to which coal utilitization technologies must be upgraded to be viable options," I don't know whether I am reading into it an implication that is not there, but I would like your comment. The implication may be that either we should reduce environmental standards and regulations or it may cast doubts on our ability to develop technology to make coal a more viable use for energy.

Mr. **Mannella**. No, that is not what I meant to convey there. What I meant to convey there is that while we are developing technology that will perform certain beneficial functions, and always keeping in mind the need to do it at an economical cost, that there is somewhat of a moving target for the degree to which the technology must perform. There is some uncertainty as to the direction or the extent of the need for environmental action.

Mr. PACKARD. Like hazardous waste and Superfund problems, the question always comes up how clean is clean. In your judgment, is that going to be a problem with coal and its usage?

Mr. MANNELLA. All I can say is that the industry will comply with whatever regulations are on the books.

Mr. PACKARD. And you are not suggesting those regulations need to be altered, then?

Mr. MANNELLA. I am not making that suggestion.

Mr. PACKARD. Do you have a feel for when we might be able to reach, if we go at the concurrent levels of research and development, when we might reach a point where coal can be used in an unlimited fashion, meeting and complying with existing environmental regulations?

Mr. MANNELLA. Well, we are using a lot of coal now, and we are meeting the environmental regulations, particularly I believe for the newer plants that come under the New Source Performance Standards. And there are technologies under demonstration now such as the integrated gasification combined cycle at Cool Water that has been mentioned, and the atmospheric fluidized bed work that has been mentioned that will be going into TVA, Northern States Power, and Colorado Ute. So it is certainly not a question that we do not have any options whatsoever on how to burn coal cleanly.

Mr. PACKARD. That is true.

Mr. MANNELLA. It is a question—and I believe that Mr. Fuqua touched on it in his opening comments—of having the technology readiness for the decisions to be made at such time that the economy dictates that they must be made.

Mr. PACKARD. Thank you, Mr. Chairman. My time is up.

Mr. BOUCHER. Mr. Bruce.

Mr. BRUCE. No questions.

Mr. BOUCHER. Gentlemen, I would like to thank you very much for your thoughtful testimony this morning. We appreciate very much your presentation.

Mr. WEBB. Thank you, Mr. Chairman.

Mr. MANNELLA. Thank you.

Mr. BOUCHER. The next panel consists of Mr. John Wootten, director of research and technology for Peabody Holding Co. and Mr. John McCormick of the Environment Policy Institute.

Gentlemen, we welcome you this morning. I would also ask the witnesses to restrict their opening statements to approximately 10 minutes and, without objection, the written statements will be received and made a part of the record.

The Chair recognizes Mr. Wootten.

STATEMENTS OF JOHN M. WOOTTEN, DIRECTOR OF RESEARCH AND TECHNOLOGY, PEABODY HOLDING CO., INC., ST. LOUIS, MO, TESTIFYING ON BEHALF OF THE CLEAN COAL TECHNOLOGY COALITION; AND JOHN McCORMICK, ENVIRONMENT POLICY INSTITUTE, WASHINGTON, DC

Mr. **Wootten**. Thank you, Mr. Chairman.

Members of the subcommittee, my name is John Wootten. I am director of research and technology for Peabody Holding Co. I am appearing before you today as a member of the Clean Coal Technology Coalition, which is a group of utilities, equipment suppliers, coal producers, architect-engineers and the National Coal Association. A membership list along with a copy of the coalition's statement in support of the clean coal program is attached to my statement. I intend to summarize my testimony in the essence of time.

Members of our coalition have joined together as varied public and private entities to promote the rapid implementation and funding of the clean coal technology development program. As you requested, Mr. Chairman, I intend to comment on the Department of Energy's report, which addresses the clean coal technologies.

The coalition does not agree with the Department's conclusion that Federal incentives will not accelerate commercialization of clean coal technologies. I believe the TVA atmospheric fluidized bed demonstration project, of which Peabody is a supporter, is a prime example of just the opposite conclusion. Federal Government participation is accelerating development of that project.

On the same day that the Department transmitted its report to Congress on clean coal submissions, the Energy Research Advisory Board, DOE's own panel of outside experts, disagreed with that very conclusion. I think there has been enough comment on that, but I will just say that the Coalition also agrees with the ERAB recommendation that DOE should intervene in that area. The Department's clean coal report simply reflects and restates pre-existing policy, that private industry should do the demonstrations.

The need to develop new coal utilization technologies is premised on two related factors. First, new electrical generation not currently planned or under construction will be needed in the 1990's to replace aging facilities, to reduce the dependence on oil and gas-fired power generation and to ensure that economic growth is not stymied for lack of adequate electrical supplies.

Second, the continued or expanded use of coal will be dependent in part upon the development of new technologies which offer cost effective means for protecting the environment while producing a reliable source of electrical energy.

This subcommittee may know that there are currently wide differences in projected future demands for electrical power. There is a consensus, however, that new capacity will be needed, even though the rate of increased demand is not agreed upon. For an annual growth rate of 2½ percent, sometime in the early to mid-1990's peak electricity demand is expected to exceed installed capacity and some new capacity above that which is already planned will have to be installed. Current trends in the utility industry strongly suggest that a new capacity may not be built in time to meet this increased need. If, for example, the projected capacity needs of the mid-1990's are being met with conventional generating units that take from 7 to 10 years to permit, design, construct and place in service, utilities must undertake those new power plants now. This construction is not being undertaken.

Further, many utilities have canceled or abandoned the construction of large baseload facilities and are now unlikely to undertake major new construction programs. Also, new demand, and therefore new capacity, requirements of many utilities will come in much smaller increments which do not warrant construction of large-scale conventional power plants.

These and other circumstances cause considerable uncertainty within the electric utility industry, and this uncertainty simply means that the utilities will be even more cautious in adding capacity, especially adding capacity which utilizes new technologies.

Beyond the need for additional capacity in the 1990's, coal use will be paced by our ability to protect the environment. Conventional coal-fired powerplants can comply with current and proposed environmental requirements, but the dollar cost is high. For example, the cost to retrofit a flue gas desulfurization system on a 10-year-old powerplant can easily exceed the original investment in that facility. As the demand for coal-fired power production increases, the current requirement for emission limitations will continue or may be made more stringent. If proposed acid rain legislation is enacted, utilities could pay approximately $200 billion over the remaining life of the plants in question in order to comply. Utilities would have no choice but to spend their limited funds to comply rather than the construction of clean coal projects.

A more desirable approach to meet the demand for electricity and to protect the environment is the timely development of new coal utilization technologies. Chart 6, which is the last chart on my testimony, attempts to depict the possible advances in emission control likely to result from development of these various clean coal technologies. Further, a number of these clean coal technologies offer shorter construction leadtime, improved fuel conversion efficiency, the ability to burn a wider variety of coals, and the opportunity to construct powerplants in modules which better match capacity additions to the need for the electricity.

While the development of these technologies may be attractive, there are a number of factors which stymie aggressive utility development. The utility industry does not operate in a free marketplace. Return on the electric utilities' investment in a new technology is governed by the Public Utility Commissions which are generally charged with the task of minimizing ratepayer costs. Risks undertaken by utilities in technology development may be placed primarily upon the shareholders of the utility and not the ratepayers.

Given that the domestic power generation market may be very limited for some time to come, coal companies and utility equipment suppliers are unable to contribute substantial dollars to the costly demonstration of new clean coal technologies.

Our coalition agrees with the DOE that the private marketplace should be responsible for the widespread commercialization of new coal technologies. However, in order to accelerate the commercialization of these technologies in the required timeframe, the sharing of the cost by the Federal Government is necessary. For its part, the private sector is willing to provide very significant private moneys toward the demonstration of new high risk technologies. The Federal Government is being asked to participate with the private sector in the commercial demonstration phase by sharing a portion of the cost for these new technologies.

Mr. Chairman, there is little time in which to address the electricity needs of the 1990's. If new coal technologies are to be utilized to meet expected capacity demands during the mid to late 1990's, those new technologies must be commercially demonstrated and available in the 1990 to 1993 timeframe. It takes approximately 3 years to design and construct a demonstration and 2 years to adequately test it. Therefore, to be available in the early 1990's, these clean coal technology demonstrations must be initiated in the 1985 to 1988 timeframe. This timeframe is already upon us.

Further, pending legislation calling for emission reductions from existing powerplants make the timely development of clean coal technologies even more acute. Compliance dates between 1990 and 1995 require that new retrofit technologies be available for use in existing plants in the 1987 to 1990 time. Given this timeframe, the commercial demonstration of technologies which can be used in retrofitting existing plants must also be conducted over the next 3 years. Otherwise, this option for compliance may not be available.

The next 10 years are very important for both assuring future environmental acceptable electrical supply and for controlling the cost of electricity. The commercial demonstration of clean coal technologies is at least one important option which this country would be wise to pursue in planning for ways to meet increased demand in an environmentally acceptable manner.

This concludes my statement, and I would be glad to answer any questions that I can.

Mr. BOUCHER. Thank you, Mr. Wootten.

[The prepared statement of Mr. Wootten follows:]

STATEMENT OF MR. JOHN M. WOOTTEN
ON BEHALF OF THE CLEAN COAL TECHNOLOGY COALITION

Mr. Chairman, Members of the Subcommittee, my name is John M. Wootten. I am Director of Research and Technology for Peabody Holding Company, Inc., the parent company of Peabody Coal Company. Peabody Coal is the largest coal producer in the United States with active operations and reserves in both the low-sulfur coal producing areas of Appalachia and the western United States, and well as the high-sulfur coal producing areas of the Midwest.

While Peabody did not submit a proposal to the Department of Energy as a part of the clean coal technology solicitation we are very interested in and supportive of this endeavor. Our company, as you may know, is a participant in the 160 megawatt atmospheric fluidized bed combustion project sponsored principally by the Electric Power Research Institute (EPRI), TVA, Duke Power and the State of Kentucky. The project is located in Paducah, Kentucky; it is currently under construction and is scheduled for start-up in 1989. Without $30 million being provided to the project by the government, which enabled the project sponsors to close a gap in the financing, this important clean coal utilization facility might have been undertaken at a much slower pace. Government assistance has clearly accelerated development.

In addition, Peabody has committed funds to two other projects and is evaluating participation in four others, all of which have submitted clean coal technology proposals to DOE. A complete commercial demonstration of these projects will require significant private sector support with an equal or lesser degree of support from government. Without government support, the commercial demonstration of these projects and other equally important clean coal projects will be slowed or left undone, preempting their timely application to meet this country's future energy and environmental goals.

INTRODUCTION:

I am appearing before your Subcommittee as a member of the Clean Coal Technology Coalition, an ad hoc group of utilities, equipment suppliers, coal companies and architecture, engineering and construction firms and the National Coal Association. I ask that the membership of our group, along with a copy of the Coalition's statement in support of the clean coal program, be included in the hearing record at the conclusion of my remarks.

The Clean Coal Technology Coalition was organized earlier this year to provide a means by which interested private and public sector parties might communicate to Congress and the Administration a collective viewpoint in support of the clean coal technology development program. Thus, no matter what interest an individual company or state government might have in obtaining government assistance for a particular technology or project, we have joined together in the hope of demonstrating to Congress that varied private and public entities support the need for a federally-assisted clean coal technology development program. Our interest as a coalition is to promote the rapid implementation and funding of a program which we believe makes imminently good sense.

On behalf of the member companies, industry associations and state governments associated with the Clean Coal Technology Coalition, I want to thank you for this opportunity to comment on the need for the program. Also, as you requested, Mr. Chairman, I intend to comment on the Department of Energy's recently submitted report to the Congress which addresses those proposals and statements of interest that were submitted to the DOE last February as a result of a Department of Energy solicitation directed by provisions of Public Law 98-473.

We do not agree with the Department's conclusion that "Federal incentives will not accelerate commercialization of these [clean coal] technologies and may be counterproductive to their development." (See page 1-4 of the Report to Congress on Emerging Clean Coal Technologies. May 1985.) The DOE states in the report that this conclusion was reached based upon "the Department's previous experiences with Federal incentives." According to the Department, most projects that have received Federal assistance in the past have not led to successful commercialization of new fossil technologies. I believe the Paducah fluidized bed combustion project is an example of just the opposite conclusion. Federal government participation is accelerating development and will greatly assist the private sector participants in providing the experience required for near-term widespread application of this technology in utility settings.

Ironically, perhaps, on the same day that the Department transmitted its clean coal report to the Congress, the Energy Research Advisory Board (ERAB), DOE's own panel of outside energy research experts, adopted a report to the Secretary of Energy which states in part

> "Within the clean use of coal area the overall DOE program is well dispersed and all major technological areas are covered in some way. However, the budget does not

> allow DOE to help with the transfer of the new technologies to the private sector and to assure their commercialization. This is the result of basic policy which should be reconsidered.
>
> In most instances, the current policy of abandoning a development after Proof of Concept has been established will result in just that, abandonment." (Page 19, emphasis added.)

The current DOE policy is to stop government involvement in technology development before the demonstration or process development stage (see Chart 1). The conclusions reached by the Department in the clean coal report simply reflect and restate this policy notwithstanding the contrary advice given by the government's own panel of outside experts.

Industry's response to the recent DOE solicitation, in which 175 submittals were made, including 159 submissions proposing specific emerging clean coal technology projects in 29 states, also evidences a view contrary to the DOE's conclusion. The private sector will proceed with, and not abandon, clean coal technology development if government support is provided to complement very substantial private sector cost-sharing. The willingness of industry to provide significant amounts of private funds, often equaling or exceeding fifty percent of the projected cost of the project, strongly evidences a commitment to projects and technologies.

Any lack of success in commercializing new fossil technologies with respect to prior DOE assisted technology development projects cannot and should not be solely attributed to DOE involvement as the Department's clean coal report suggests. If such a conclusion has validity, then the solution is to fashion a government/private sector partnership that works rather than to conclude that commercialization has been unsuccessful whenever the government gets involved. As the ERAB report suggests, the alternative is equally unappealing, that is, technologies will be abandoned if government assistance beyond research and development is not provided.

THE NEED FOR NEW COAL UTILIZATION TECHNOLOGIES:

The need to develop new coal utilization technologies is premised upon two related factors. First, new electrical generation, not currently planned or under construction, will be needed in the 1990's to replace aging facilities, to reduce dependence upon oil- and gas-fired power generation and to ensure that economic growth is not stymied for lack of adequate electrical supplies. Secondly, the continued or expanded use of coal will be dependent, in part, upon the development of new technologies which offer cost-effective means of producing electricity or providing energy for industrial use while also assuring environmental protection.

I. NEED FOR NEW ELECTRICAL CAPACITY

Projecting future electricity demand has been particularly difficult and controversial for many utility planners and outside analysts who have projected growth of electricity demand ranging from less than one percent to about five percent annually over the next 10 to 15 years. The Edison Electric Institute, recognizing these widely varying projections, states in its recently published report on nuclear power: "It is possible that the additional generating capacity needed by the year 2000 could be as little as a few million kilowatts and as much as 500 million kilowatts -- or about three quarters of today's installed capacity." (At page 17, Report of the Edison Electric Institute on Nuclear Power, February 1985.) These wide differences in projected future demand result, in part, from unknown factors about economic growth and the future use of electricity. Further, other significant unknowns include possible additional environmental legislation and regulation which might impact the continued service of existing units, further nuclear deferments, oil supply interruptions, the yet-to-be-proven ability to concurrently increase both the availability and life of existing capacity and the success of further conservation, load management efforts and other demand-reducing programs.

There is general consensus that new capacity will be needed even though the rate of increased demand is not agreed upon. The electric utility industry through the projections of individual companies aggregated by the North American Electric Reliability Council is projecting growth in electricity demand of 2.5 percent annually through 1993.

According to the Edison Electric Institute:

> "With demand growth of 2.5 percent and a capacity margin of 20 percent, additional capacity is needed by 1992 and a total of 152 million kilowatts of new capacity or demand reductions will be needed by the year 2000. Of this need, 34 million kilowatts of capacity have been reported to North American Electric Reliability Council as planned but not under construction.

> In the present economic and regulatory environment, some of the nuclear units now under construction may not be completed or permitted to operate. For example, if 8 million kilowatts of the capacity under construction are cancelled and if one third of the units over 40 years are retired, the capacity needed by the year 2000 would total 192 million kilowatts with demand growth of 2.5 percent." (Report of the Edison Electric Institute on Nuclear Power, February 1985, at page 20.)

The EEI has concluded that "100 to 200 million kilowatts of new generating capacity will be needed -- in addition to units still under construction today -- before the year 2000." Attached to this statement are chart 2, which depicts U.S. electric generating capacity and peak demand between 1984 and 2000 and chart 3, which depicts U.S. electric generating capacity and peak demand with possible cancellations and retirements between 1984 and 2000. Each chart attempts to display how different projected growth scenarios will impact upon electricity capacity. If, for example, a demand growth rate of 2.5 percent is achieved then sometime in the early 1990's peak electricity demand is expected to exceed installed capacity and some new capacity above what is already planned will be required.

Current trends and the recent history of the utility industry strongly suggest that new capacity may not be built in time to meet increased demand. If, for example, the projected capacity needs of the mid-1990's are to be met with conventional generating units that take from 7 to 10 years to permit, design, construct and place in service, utilities must undertake those new power plants now. That construction is not being undertaken and, in fact, the electric utility industry is entering a period in which relatively little new generating capacity will be under construction and many companies have completed or will soon complete building programs. Further, many utilities, which only recently were forced to cancel or abandon the construction of large base load facilities, including conventional coal-fired power plants, are not now likely to undertake major new construction programs. Also, it is projected that new demand and, therefore, new capacity requirements for many utilities will come in much smaller increments which do not warrant construction of large scale conventional power plants. And, finally, because the growth of electricity demand has slowed considerably, so that electricity growth now about equals the growth of the economy, any miscalculations by utility planners in projecting demand could result in excess capacity being built. The cost of such capacity cannot be easily recovered when there is no longer the periods of rapid growth which once characterized the utility industry and ensured that excess capacity would be quickly utilized. In fact, regulatory commissions have little sympathy toward allowing the recovery of investments for capacity built in excess of real demand and have, in some instances, forbidden the recovery of new, excess installed generation. These and other circumstances cause considerable uncertainty within the electric utility industry and this uncertainty simply means that utility executives will be ever more cautious in adding capacity.

There appears, therefore, to be little impetus and even less time in which to address the electricity needs of the 1990's. If new clean coal technologies are to be utilized to meet expected capacity demands during the mid- to late 1990's, those technologies must be commercially demonstrated and available in the 1990 to 1993 time frame. It takes approximately 3 years to design and build a commercial demonstration and 2 years to conduct testing. Therefore, to be available in the early 1990's these clean coal technology demonstrations must be initiated in the 1985-1988 time frame. That time frame is already upon us. The next ten years are very important in both assuring future environmentally acceptable electricity supply and in controlling the costs of electricity. The commercial demonstration of clean coal technologies is at least one important option which the country would be wise to pursue in planning for ways to meet increased demand.

II. NEED TO DEVELOP COST-EFFECTIVE COAL UTILIZATION TECHNOLOGIES WHICH ENSURE CONTROL OF EMISSIONS

The important goal of protecting the environment and minimizing sulfur dioxide, nitrogen oxide and particulate emissions which result from the combustion of an inherently dirty fuel might be achieved in a number of ways. To date, industry has responded to regulatory controls by fuel switching, by pre-combustion coal cleaning, and by installing post-combustion pollution control devices. Conventional coal-fired power plants can comply with current and proposed environmental requirements, but the dollar costs are high. To put these costs in perspective, the cost to retrofit a flue gas desulfurization system to a 10-year-old power plant can exceed the original investment in the facility. Also, approximately 40 percent of the capital investment and 30 percent of the total cost of power for new, coal-fired power plants are related to environmental control. Finally, the use of flue gas desulfurization technology and other pollution control devices has a major impact on the efficiency and reliability of coal-fired power plants.

As the demand for coal-fired power production increases, the current requirements for emission limitations will continue or these emission limits might be made more stringent by new legislation or regulation. The resulting costs associated with protection of the environment are a large and growing percentage of the cost of each kilowatt generated. It is important to understand that if the public demands even more stringent requirements for greater protection of the environment, the cost of compliance will take utility dollars away from clean coal technology development projects. For example, the Electric Power Research Institute has testified before the Congress that proposed acid rain control legislation that would require retrofitting flue gas desulfurization equipment on up to 100,000 megawatts of existing power plants burning high sulfur coal would cost approximately $200 billion over the remaining life of the plants in question. If these requirements were imposed, utilities would have no choice but to expend limited funds to comply with new regulations.

Another option to assuring protection of the environment besides simply promulgating additional regulations is to encourage the timely development of clean coal technologies. These new coal utilization technologies, besides assuring compliance with emission controls, also promise more cost-effective generation of electricity from a greater variety of coal resources. An opportunity for the timely development of these technologies should be provided.

Much has been written about the development and potential of new coal utilization technologies. Charts 4, 5 and 6, which are attached to this testimony, attempt to describe the variety of technological options which are currently being pursued. These emission control options range from improved physical coal cleaning to furnace sorbent injection (e.g. LIMB), improved methods of combustion and advanced scrubbing technologies. Importantly, these technologies promise very significant improvements in the control of emissions from the use of coal. Chart 6 attempts to depict the possible advances in emission control likely to result from development of these various technologies. Further, a number of these clean coal technologies offer control of both sulfur dioxide and nitrogen oxide emissions, shorter construction lead times, improved fuel conversion efficiency, an ability to burn a wider variety of coals and the opportunity to construct power plants in modules which better match capacity additions to anticipated increased demand.

Pending legislation calling for emission reductions from existing power plants make the problem of timely development of clean coal technologies even more acute. Compliance dates between 1990 and 1995 require that new retrofit technologies be available for use in existing plants in the 1987-1990 time frame. Given this time frame, the commercial demonstration of technologies which can be used in retrofitting existing plants must be conducted over the next three years. Otherwise, this option for compliance might not be available.

It should be emphasized that no single clean coal technology is now thought to satisfy the variety of existing or projected coal-fired utility or industrial power generation requirements. All of those technology options which are mature and ready for commercial-scale demonstration should be considered likely candidates for the clean coal technology development program.

FACTORS WHICH INHIBIT PRIVATE SECTOR DEVELOPMENT OF CLEAN COAL TECHNOLOGIES

The principal user industry of new clean coal technologies will be the electric utility industry. This industry is constrained in the amount of effort that can be directed toward large-scale, high-risk demonstration projects. This constraint is principally a function of the fact that the utility industry does not operate in a free marketplace. Return on an electric utility's investment is governed by public utility commissions that are generally charged with the task of minimizing ratepayer costs; risks undertaken by utilities in clean coal technology development will not necessarily be reflected in allowed profits or rewards. Indeed, if failure occurs, the burden may be placed primarily upon the shareholders of a utility not the ratepayers. At a minimum, the costs involved in constructing a clean coal project, unless somehow characterized as research and development, must be carried by the utility until that time when the plant is placed into service. This burden of carrying construction costs when added to the prospect that the facility might not be reliably placed into service at all creates too great a financial exposure for many utilities.

Furthermore, many utilities still face severe financial problems and cannot even raise capital funds for improvement or expansion of existing or new conventional electric power generation. This circumstance makes funding high risk clean coal technology development projects even more difficult.

Coal companies and utility equipment suppliers are also not able to bear the burden alone of significant investments in new technology development. Given the possibility that the domestic power generation market may be very limited for some time to come, such entities are reluctant to contribute substantial dollars to the costly demonstration of new clean coal technologies when the returns on their investments may be very limited.

A final factor which inhibits private sector development of new clean coal technologies is that once the demonstration stage of technology development is reached enormous expenditures for engineering, construction, manufacturing, capital formation and operation are required. A new, "greenfields" clean coal technology project may require 5 years to design and construct and test. The exposure to project participants during the construction and demonstration phase which may result from changes in government policy or any number of other unanticipated occurrences can be so great as to result in utilities and other interested parties simply refusing to take significant risks. In addition, major modifications to the technology may be required after start-up, thus necessitating the expenditure of additional capital.

The Clean Coal Technology Coalition agrees with the DOE that the private marketplace should be responsible for the widespread commercialization of new clean coal technologies. However, the normal cycle of development which generally provides the private sector with sufficient time to commercialize a technology has been significantly disrupted. The private marketplace is currently faced with a dramatically changing picture in which the supply of electricity, now is surplus, may soon be outstripped by demand. Further regulations or new legislation may require costly modifications to existing facilities or more costly generation from any newly-constructed conventional power plants.

These changes, some of which may be imposed by government, necessitate a program of parallel government assistance like that envisioned by the clean coal program so as to assure timely development of technologies which may prove useful in cost effectively addressing these changes. Thus, in order to accelerate the commercialization of clean coal technologies and, in some instances, to ensure that the technology is not abandoned after the research and development stage, some sharing of the costs by the federal government is highly desirable. For its part the private sector is willing to provide very significant private monies toward the demonstration of new, high risk technologies. The federal government is being asked to participate with the private sector in the commercial demonstration phase by also sharing a portion of the costs of new technology development.

THE ROLE OF THE FEDERAL GOVERNMENT IN THE DEVELOPMENT OF CLEAN COAL TECHNOLOGIES

The clean coal technology development program envisions a partnership between the federal government and the private sector. This relationship is justified if the public receives benefits for the public funds sought to be expended.

Although it is possible that some technologies which could be supported by the clean coal program may never be commercialized, the fact that the private sector will be required to provide a large portion of the funds for a project increases the likelihood that early commercialization will occur. Therefore, an important public benefit is that this clean coal program is designed to provide the greatest assurance that these technologies, once demonstrated with the assistance of public funds, are likely to then be used in widespread near term commercial applications.

Accelerated commercial demonstration is also very important if the Nation is to receive the benefit of new technologies when the need for new capacity arises in the 1990's. Early and widespread application of new coal utilization technologies which are less costly than current alternatives, which can be constructed and brought on line more quickly than current alternatives and which can be constructed in smaller -- even modular -- units to more nearly meet current demand requirements, are all benefits to be received by the public from successful implementation of the program. Also, technologies that might enable retrofitting of existing power plants to reduce or better control emissions and/or increase efficiency might also be demonstrated under the clean coal program.

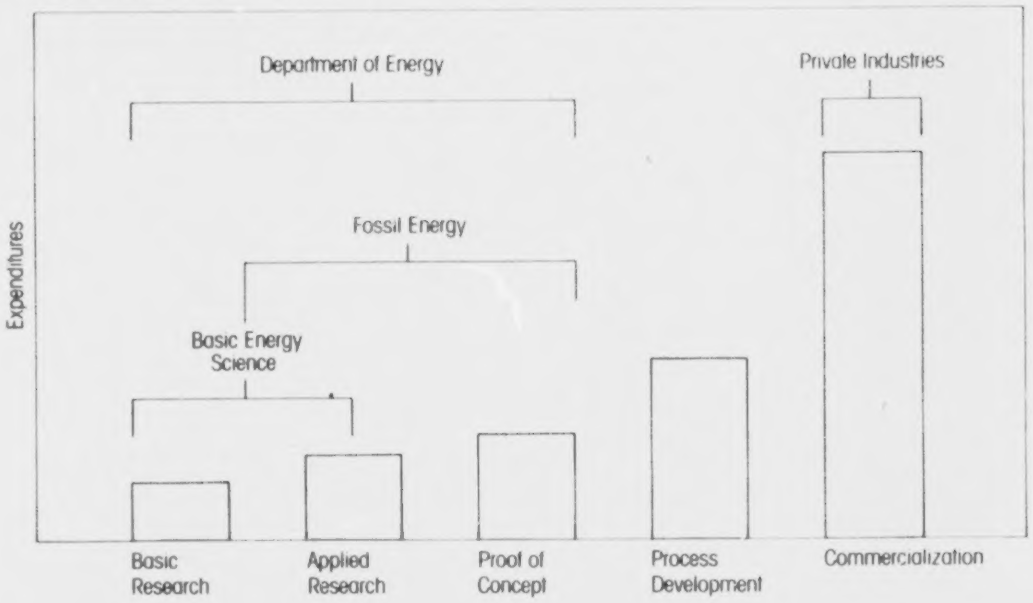
The public benefits of early commercialization of clean coal technologies, which include the promise of better environmental protection, more cost-effective production of electricity and more efficient use of our coal resources, are compelling reasons to implement the clean coal technology program rapidly.

CONCLUSION

Mr. Chairman, on behalf of the Coalition, we applaud your interest and leadership in this important program. We have an opportunity to create a unique partnership between the government and the private sector. The marketplace has identified the technologies to be commercialized; the private sector is ready to commit very substantial funds to these projects; and our members are willing to put their projects into the competitive arena.

From the point of view of the Clean Coal Technology Coalition, we would encourage rapid implementation and sufficient first-year funding to ensure that industry will aggressively participate in this program.

CHART 1
Technology Development Path



The Technology Development Path

These Steps Are Defined Briefly as Follows

Basic Research:

Studies Directed Towards Development of Fundamental Scientific Knowledge Leading to the Definition of New Energy R&D Concepts;

Applied Research:

Activities to Resolve Broad Engineering and Physical Science Problems in Specific Fossil Technologies and Related Areas; However Practical Utility May Not Be Proven At This Stage;

Proof of Concept:

Development to Resolve Specific Problems to Determine the Technical and Environmental Feasibility of the Integrated Process. Data is Generated to Evaluate Critical Scale-Up Parameters, Characterize Sub-Systems, Processes, and Products, and to Permit Preliminary Economic Projections to be Made;

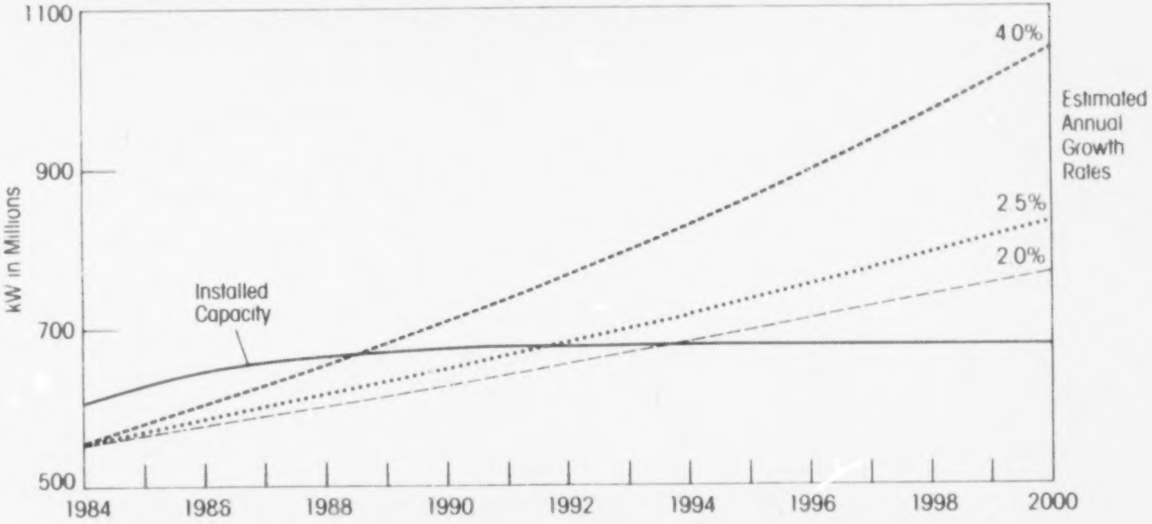
Process Development:

Increasingly Larger Scale Engineering Design, Construction and Operation of Energy Systems With the Objective of Reducing Technical Risks and Improving the Process Operability, Reliability, Economics, and Environmental Impact;

Commercialization:

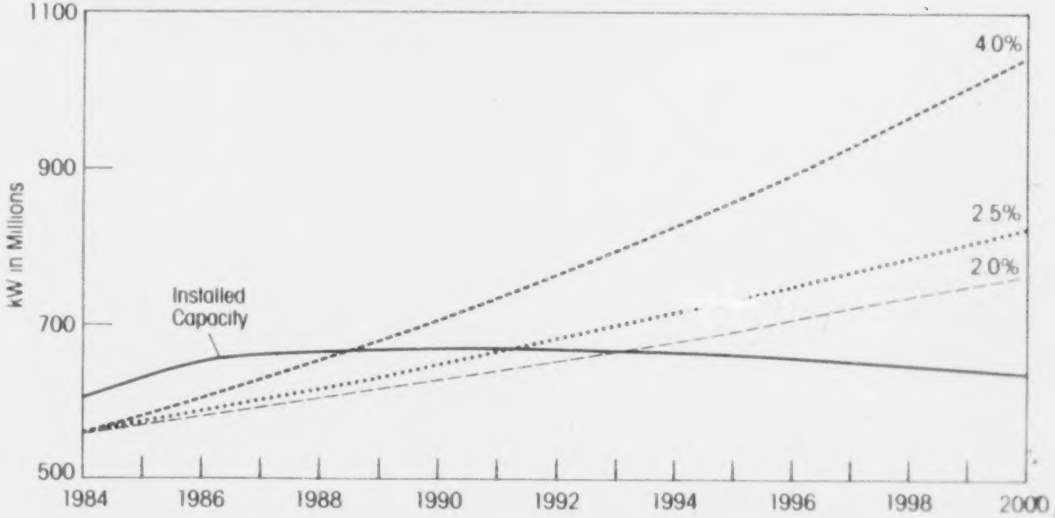
Wide Variety of Efforts to Eliminate Technical, Economic and Institutional Barriers Required for Acceptance of a New Energy Technology into the Marketplace.

CHART 2
U.S. Electric Generating Capacity and Peak Demand, 1984-2000



Note: Peak demand at stated growth rates with 20% capacity margin needed for dependable supply. Includes existing capacity and capacity under construction less retirements of 15 million kilowatts through 1993 as reported to NERC.

CHART 3
U.S. Electric Generating Capacity and Peak Demand With Possible Cancellations and Retirements 1984-2000



Note Peak demand at stated growth rates with 20% capacity margin needed for dependable supply. Includes existing capacity less retirements reported to NERC and assumed retirements after 1993. and capacity under construction less assumed cancellations

CHART 4
Coal Utilization

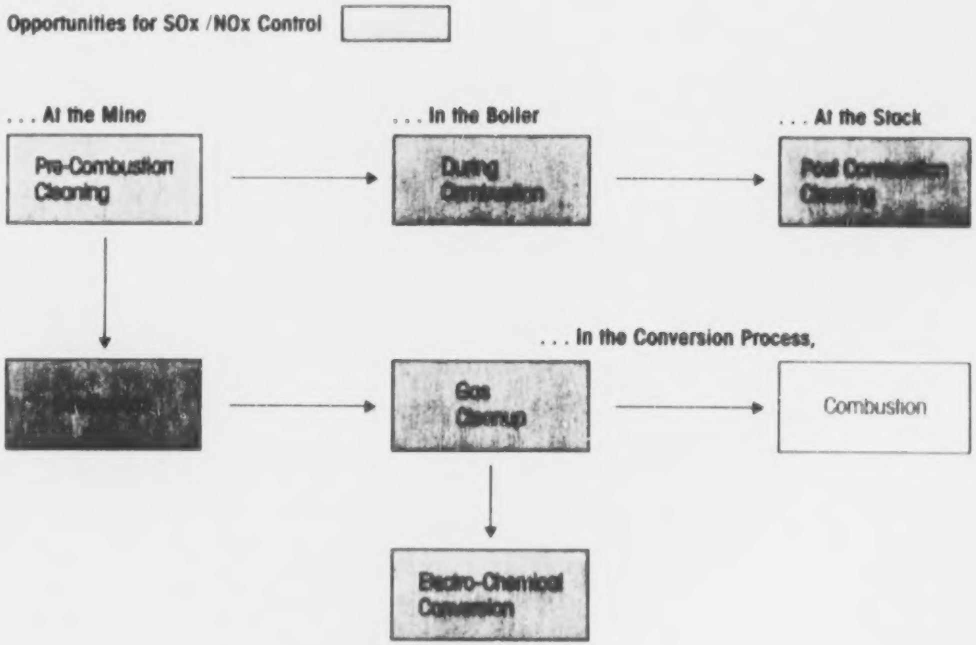
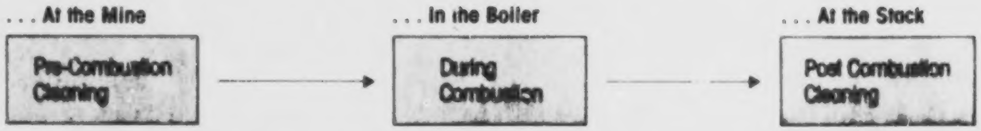

Opportunities for SOx / NOx Control
. . . At the Mine
Pre-Combustion Cleaning
. . . In the Boiler
During Combustion
. . . At the Stack
Post Combustion Cleaning
. . . In the Conversion Process,
Gas Cleanup
Combustion
Electro-Chemical Conversion

CHART 5
Coal Utilization

Opportunities for SOx /NOx Control ☐



. . . At the Mine

Pre-Combustion Cleaning

- Fine Grinding
- Dewatering (Low rank coals)
- Physical Cleaning
  and/or
- Chemical Cleaning

. . . In the Boiler

During Combustion

- Reconstitution
- Atmospheric Fluidized Bed
- Pressurized Fluidized Bed
- Low-NOx Combustors
- Slagging Combustors

. . . At the Stack

Post Combustion Cleaning

- Furnace Sorbent
  Injection Technologies
- Flue Gas Desulfurization
  (Scrubbers)
- Advanced SOx /NOx Scrubbing

(Integrated Gasification Combined Cycle and Magnetohydrodynamics offer similar SOx /NOx control opportunities with differing techniques.)

CHART 6

Emerging Technologies for SO_2/NOx Removal Potential

98-99%

- *Gasifier/ Combined Cycle (N)*

95%

- *Utility Atm. Fluidized Bed (N, R)*
- **Advanced Scrubbing (N, R)**

50-85%

- *Furnace Sorbent Injection Technologies (R)*
- **Retrofittable Partial Scrubbing (R)**
- *Retrofittable Partial SOx/NOx Scrubbing (R)*
- **Advanced Coal Cleaning (R)**

90% or Greater

- *Pressurized Fluidized Bed (N, R)*
- *Adv. Gasifier/ Combined Cycle (N)*
- *Gasifier/Fuel Cell Combined Cycle (N)*
- *Advanced SOx/NOx Scrubbing (N, R)*

98-99%

- *Adv. Gasifier/Fuel Cell Combined Cycle (N)*

Symbols

Sulfur Removal Only
Sulfur and Nitrogen Removal
N—New Plant
R—Retrofit

CLEAN COAL TECHNOLOGY COALITION
1050 Thomas Jefferson Street, N.W.
Seventh Floor
Washington, D.C. 20007
(202) 331-9400

Co-Chairs:
The Signal Companies
American Electric Power

Statement of Support for the Clean Coal Program

The Clean Coal Technology Coalition supports the timely implementation and funding of a clean coal program which will result in the demonstration of technologies that use coal in an environmentally acceptable manner, at reasonable cost and which will operate reliably in utility systems and in large industrial applications.

Clean coal technologies must be demonstrated at or near commercial scale before they will have the confidence of the electric utilities industry and the agencies which regulate it. Most of these emerging technologies are not yet sufficiently advanced to have gained this acceptance. A regulated utility acting alone is constrained in its ability to support new technologies. Current regulatory policies impede the incorporation into the rate base of the research and development expenses associated with the commercialization of clean coal technologies. This requires utility companies to shoulder significant financial burdens. The Clean Coal Technology Reserve created by Congress in Public Law 98-473 would provide the stimulus necessary to assure the earliest practicable commercial availability of these emerging technologies.

The private industry/government partnership created by the Clean Coal Program is the least costly and most effective course the United States can pursue to ensure environmentally and economically acceptable use of our most abundant fossil energy resource. Furthermore, successful commercialization of clean coal technologies will significantly advance the national goals of utilizing this immense domestic energy resource in an environmentally acceptable manner, while providing electric utility customers and industrial users of coal with a more secure energy supply at reasonable prices.

CLEAN COAL TECHNOLOGY COALITION
Membership - May 7, 1985

Babcock & Wilcox
1735 Eye Street, N.W.
Suite 814
Washington, D.C. 20006

Southern Company Services
1101 17th Street, N.W.
Suite 405
Washington, D.C. 20036

Transamerica Delaval
8181 Professional Place
Suite 116
Landover, Maryland 20785

Peabody Holding Company
1120 20th Street, N.W.
Suite 720
Washington, D.C. 20036

Public Service Co. of Indiana
1920 N Street, N.W.
Washington, D.C. 20036

Southern California Edison
1111 19th Street, N.W.
Suite 303
Washington, D.C. 20036

Florida Power & Light Company
1111 19th Street, N.W.
Suite 1102
Washington, D.C. 20036

Niagara Mohawk Power Corporation
300 Erie Boulevard West
Syracuse, New York 13202

Baltimore Gas & Electric Company
1100 Connecticut Avenue, N.W.
Suite 530
Washington, D.C. 20036

MEI Systems Inc.
3121 West Spencer Street
Appleton, Wisconsin 54914

Black, Sivalls & Bryson
P.O. Box 27125
Houston, Texas 77227

American Electric Power
Service Corporation
1667 K Street, N.W.
Suite 450
Washington, D.C. 20006

Stone & Webster Engineering
1875 Eye Street, N.W.
Suite 550
Washington, D.C. 20006

The Signal Companies, Inc.
2550 M Street, N.W.
Suite 600
Washington, D.C. 20037

TRW
1000 Wilson Boulevard
Suite 2600
Arlington, Virginia 22209

Duke Power Company
P.O. Box 33189
Charlotte, North Carolina 28242

National Coal Association
1130 17th Street, N.W.
Washington, D.C. 20036

General Electric Corporation
National Place, Suite 895
1331 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Consolidation Coal Company
1701 Pennsylvania Avenue, N.W.
Suite 900
Washington, D.C. 20006

Public Service Electric & Gas Co.
80 Park Plaza
Newark, New Jersey 07101

Mr. BOUCHER. We will proceed momentarily to Mr. McCormick's statement. We have a call of the House pending at the moment, and I am going to ask that the subcommittee recess for approximately 10 minutes. When we return we will hear your statement and ask questions of both witnesses.

The committee stands in recess.

[Recess.]

Mr. BOUCHER. The subcommittee will reconvene.

At this time we will be glad to hear the statement of Mr. John McCormick.

Mr. MCCORMICK. Thank you, Mr. Chairman.

Mr. Chairman, my name is John McCormick. I am a Washington representative of the Environmental Policy Institute. It is a pleasure to be here this morning to discuss an issue of vital importance.

Mr. Chairman, I have a lengthy statement that I would like to submit to the record——

Mr. BOUCHER. Without objection, the statement will be received.

Mr. MCCORMICK [continuing]. And make some comments before I address the specifics of the hearing this morning.

Mr. Chairman, our organization of many environmental groups have been opposed to massive Federal outlays of subsidies for synthetic fuels development. Since 1974 we have held that view, and I think history has borne us right, that we took the correct view. Because had some of those plants been built in the early 1970's, I think many of those companies would be hammering on the doors of the Congress begging for additional price supports.

Well, now, Mr. Chairman, we are faced with a new proposal, and I think this proposal has a great deal of merit, Mr. Chairman, if it is directed at the most pressing needs of the day; and that is, how to help the electric utility industry, which, as we heard this morning, is a consumer of about 80 percent of the U.S. coal produced. How are we going to help that industry to cope with the increasing demands that we will make on it in terms of pollution control?

Mr. Chairman, this program could address those very pressing needs and wouldn't require a great deal of money, nor a great deal of time. Because, fortunately, we haven't been standing still in the 10 years that we have been discussing synthetic fuels, we have been moving on some very promising coal utilization technologies; and in particular, the limestone injection multistage boiler, which EPA has headed up for about 5 years, and the team of combustion engineers that Frank Princiotta of EPA at Research Triangle Park has put together are very capable of taking on a large part of the responsibilities that a clean coal technology program might have.

And having said that, Mr. Chairman, I would like to go into several criteria or goals or, let's say, constraints on how this program might be conducted so that we get maximum return for the taxpayers' dollar.

To begin with, Mr. Chairman, we recommend that the EPA must have consultation and concurrence roles and preferably at the level of the Assistant Administrator for Research and Development. And given the work that the EPA has done on the LIMB Program and on scrubber technology, I think they are totally suited to that role.

Second, Mr. Chairman, those pollution control technology candidates which promise attainment or better than attainment of current air pollution standards under the Federal and State laws should have first access to the funds. And there, Mr. Chairman, I am saying that where we have States with low State implementation plan requirements for sulfur dioxide emissions there is still a need to improve where those States in the Midwest have less stringent air pollution control requirements, and in any of the acid rain proposals that have been offered to the Congress it would require significant reductions in those Midwest States.

Utilizing existing laboratories and equipment and facilities would obviously save money, and I think the academic, industrial, and Government research centers should be used to the utmost.

Where possible share research projects with the Canadian Government. We understand that the fiscal year 1986 EPA budget does not have enough money for the LIMB demonstration of a tangential-fired boiler unit. While its cousin, the wall-fired boiler is presently being retrofitted for LIMB, we feel that demonstration of LIMB on a wall-fired boiler doesn't provide much assurance to the operator of a tangential-fired boiler that LIMB can work on that equipment as well. It just so happens that in Saskatchewan there is a 300 megawatt, tangential-fired unit that is burning lignite, which could, if the engineers can work out the details, be a host for demonstration of LIMB on a tangential-fired boiler using Midwest high sulfur coal.

Candidate projects designed to meet and improve upon the new source performance standard should be accorded the highest priority among candidate technologies.

Mr. Chairman, we have been looking at the numbers of the growth in the electric utility sector, and while that is still a very iffy question, the ultimate new capacity of the utility sector at any given time in the future, we see the potential for new growth in emissions from the utilities sector at the same time we are trying to reduce overall emissions through hopeful enforcement of an acid rain control law.

The second highest priority should go to those technologies designed to retrofit existing equipment while achieving at least a 70-percent reduction of SOx and NOx emissions. It is becoming apparent that the electric utility industry for all the obvious economic reasons is having to hold onto its older equipment longer. That is a frustration of the goals of the Clean Air Act, because it was intended that as these older plants would live out their useful life new source performance standard plants would replace them and we would see a constant downturn in emissions. But that isn't going to happen the way it was intended. It is a glitch in the Clean Air Act which must be addressed, and we are proposing that Congress consider mandatory guidelines for the retrofit of old boilers. And while it may be in the consumers' interest to hold those older plants on line longer, it is in the interest of those living downwind of those plants to see that emissions are reduced in the course of that retrofit.

Candidate technologies should have no more than 24- to 36-months startup and shakedown schedule. We are looking again, Mr. Chairman, at immediate results. We feel that there are enough candidates among that 174 provided the DOE that we could take from that those which are on the verge of going to commercialization, and this 24- to 36-month timeframe would force those—well, it would help in making the decision which technologies this money could force into commercialization.

And finally, Mr. Chairman, waste disposal research should be given a high priority as well. We recognize the problems that use of stack gas scrubbers causes, but we also know that in countries like Japan they are finding uses for the byproducts of coal-fired electric generation. They are finding that the spent ash can be upgraded and used as a soil fertilizer, and in the U.S. companies are contracting with electric utility companies using scrubbers to buy their sludge and to upgrade that sludge and it becomes usable products for wallboard, for light construction material.

Mr. Chairman, to sum up my statement, let me say that for this program to win the support of the Congress, and particularly the Appropriations Committee, we believe it is going to take the support of the downwind States to fund this program. I think it is going to be a bit much to ask those legislators who can't find money to increase EPA's research for even indoor air pollution to spend another $100 million on clean coal technology when there isn't real assurance that their constituents are going to get much in return for it.

With that, Mr. Chairman, I want to say that we will work with you to design a program that will meet the goals that the Nation, and particularly the electric utility industry, deserves if we are going to outlay another $100 million.

Thank you, Mr. Chairman.

[The prepared statement of Mr. McCormick follows:]

ENVIRONMENTAL POLICY INSTITUTE

TESTIMONY OF JOHN L. McCORMICK
BEFORE THE SCIENCE AND TECHNOLOGY COMMITTEE
CLEAN COAL TECHNOLOGY RESERVE
MAY 7, 1985

= = = = = = = = = = = = = = = = =

Mr. Chairman, and Members of the Committee,

It is a pleasure to appear before you this morning to discuss an issue which has the potiential to make a very important contribution to the Nation's energy and air quality debates. The Environmental Policy Institute has been involved in this issue of energy research since our establishment in 1972. From the outset, let me assure you that we are not opposed to the mining or utilization of coal. We worked with Chairman Udall and Senators Jackson and Metcalf for seven years until the Congress enacted the federal coal strip mining law in 1977. We continue our involvement in the federal coal leasing and synthetic fuels debates also.

The nation's repeated efforts to adopt and maintain an organized energy policy have not produced any agreement of a total package. Instead, we discuss energy conservation, importing fuels, burning certain fuels while banning others, and even the control of the pollutants from our use of energy in separate and isolated pieces. This Committee has an opportunity to integrate some of these vital components in one piece of legislation. We come to you with a list of criteria which this Committee should consider as it proceeds with the establishment and funding of a Clean Coal Technology Reserve.

218 D Street S.E. Washington D.C. 20003 (202) 544-2000

Before I begin, though, there are several points which must be made.

a. The regulation of the coal surface mining industry since 1977 has not damaged its market. While a much improved regulatory process has been enforced by State and federal agencies, the tonnage rates have increased steadily. Where major contracts for strip mined coal have been cancelled or cut back, it is the quality of the coal that was at issue, not that its producer had to backfill a highwall.

b. Coal has not yet taken the economic nosedive that the nuclear power industry has, but it would not be wise to rule that prospect out at this time.

c. The international coal market is fighting to capture larger markets at the same time its governments are funding research to understand the planet's feedback about the possible consequences of a buildup of carbon dioxide in the atmosphere.

d. There is a growth potential for coal utilization which the U.S. can accommodate; but it is nowhere near the projections which have consumption doubling by the turn of the century, or sooner. There are no signs to confirm the logic of that optimistic view.

e. The U.S. coal industry's real problems are in the here and now. And, we have scientific knowledge and equipment readily available to meet the needs of today's coal producers and users.

f. The Clean Coal Technology Reserve is a part of the Congressional "air pollution/acid rain" debate, but it is NOT THE SOLUTION. That debate must continue to sharpen its focus as the engineering community teams up with the environmental regulators to get on with the task of making our coal use policy fit with our larger environmental and public health goals. We have the means to accomplish this.

Mr. Chairman, as you know, we took a hard line position in the mid-1970's against the creation of a federal guaranteed loan program for the establishment of a synthetic fuels industry in the U.S. When other Committees began to get involved in that matter it became increasingly more cloudy and less popular and the results of the past decade are a vindication of those who opposed massive federal involvement in a non-existent industry for unknown costs. Had some of those Southwest coal gasification proposals been built in the late 1970's some corporations would be banging on the Capital door pleading for price supports for $8 gas in a $3 market.

The last vestage of this approach to federal intrusion into the domestic energy supply industry will hopefully slip into the abyss when the House approves Synthetic Fuels Corporation deauthorization legislation pending in the House Energy and Commerce Committee. This debate has been lengthy and expensive in terms of the time the Congress has devoted to the discussion of exotic fuels production technology while ignoring the obvious needs of our basic fuels production industry - the domestic coal industry.

If this Committee intends to convince the Appropriations Committee to fund the Clean Coal Technology Reserve, it will need the political support of those legislators living downwind of smokestack plumes from today's coal burning furnaces. These are the same politicians who have to explain why the E.P.A. budget for air quality monitoring equipment and the research of air pollution effects on forests and public health cannot be increased in a year of tough federal spending debates. The Environmental Policy Institute is willing to carry this Committee's bill to some of those legislators and urge them to support it. But, it would have to accomplish certain goals and contain several requirements and limitations on the Program's goals. The following are criteria and procedures which should be applied to the Program. We urge this Committee to consider them as it authorizes a federal/private sector research program that will return a dividend on the taxpayer's investment.

1. THE E.P.A. MUST HAVE CONSULTATION AND CONCURRENCE ROLES, PREFERRABLY AT THE LEVEL OF ASSISTANT ADMINISTRATOR FOR RESEARCH AND DEVELOPMENT

The on-going research of the various coal combustion technologies by the E.P.A. is underfunded but competently managed. The team of combustion engineers that Frank Princiotta, Director of Industrial Environmental Research Laboratory assembled at RTP are first-class engineers and their development of the LIMB demonstration program is on time and on track. Their efforts are direct responses to the air quality regulation needs of the Agency and that kind of integrated approach will continue to assure that the research fits rational goals and immediate tasks. His shop is not "supply" oriented. It's focus is on pollution control and emissions reduction. Limited funding of the Clean Coal program should be no great problem for a lean and productive effort such as Princiotta manages.

2. THOSE POLLUTION CONTROL TECHNOLOGY CANDIDATES WHICH PROMISE ATTAINMENT -OR BETTER THAN- OF CURRENT AIR POLLUTION STANDARDS UNDER STATE AND FEDERAL LAWS SHOULD HAVE FIRST ACCESS TO FUNDS

A coal research program with a budget of $100 million must be strictly focused or it will squander its resources quickly and have little or nothing to show for its investment. Looking at the potential research candidate list and the project costs they represent, it is clear that the energy supply projects are very expensive in contrast to those which are designed to limit pollution emissions. The problems of fuel supply, in the U.S., are partially being solved by market forces. Shifts within the industrial fuels-buying market are taking place constantly and individuals are making changes in their lifestyles and consumer habits which have been acceptable. Therefore, the Program should not even consider those candidates which add new fuel sources to the market. We may need them over time but not now and not at $100 million per year.

3. UTILIZE EXISTING LABORATORIES, EQUIPMENT, FACILITIES AND PERSONNEL TO HOLD DOWN COSTS AND TAP AVAILABLE EXPERTISE IN THE ACADEMIC, INDUSTRIAL AND GOVERNMENT RESEARCH CENTERS.

The work the Electric Power Research Institute has underway is a valuable investment for the Nation's electric utility customers. Under the leadership of Curt Yeager, Vice President of the Coal Combustion Systems Division, EPRI is making headway on the use of fluidized-bed coal combustion equipment for large base-load electric generation and for the retrofit of older boilers. Its work on lime sorbents and low NOx boilers can be expanded quickly if the Clean Coal Program has the flexibility to dovetail the efforts of each.

The Department of Energy's Pittsburg and Morgantown facilities are located where the longterm needs of the coal industry are most acute; in the high sulfur coal regions. The acceleration of chemical coal washing research must be included on any list of priorities in the Clean Coal Program. And, the full spectrum of concerns about down stream pollution control needs should be incorporated in the design of coal cleaning technologies where large amounts of residues are generated.

4. WHERE POSSIBLE, SHARED RESEARCH PROJECTS WITH CANADIAN GOVERNMENT AND INDUSTRY SHOULD BE ENCOURAGED.

The EPA's LIMB demonstration program has no funding for the design and testing of that SO_x and NO_x control equipment on a tangential-fired boiler. That the wall-fired boiler LIMB test is proceeding is good news indeed. But, operators of tangential boilers (about 45% of the U.S. boiler market) will learn very little from that success. However, the Canadians have tested LIMB on a tangential boiler in Saskatchewan Power Corporation's Boundary Dam Unit #6. This 300 MW, lignite-fired boiler may have the capability to be modified for a test burn of medium and high sulfur bituminous coals mined in the Midwest and Northern Appalachian fields. The costs would be minimal compared to the capital demand for such a test in a boiler not already LIMB retrofitted. The costs of shipping the coal to the Saskatchewan plant would be minimal and test results would be available within 18 months. This should be discussed with the Canadians and I will furnish this Committee with the names of company officials to whom I was referred by Canadian representatives.

Since the concerns of the Canadians about U.S. footdragging on the "acid rain" issue will not be satisfied by Congressional pollution control legislation any time soon, it would be a welcome jesture to extend to our neighbors that we do want to find a resolve to the transboundary air pollution problems we share.

5. CANDIDATE PROJECTS DESIGNED TO MEET AND IMPROVE UPON NEW SOURCE PERFORMANCE STANDARDS OF THE CLEAN AIR ACT SHOULD BE ACCORDED THE HGIHEST PRIORITY AMONG CANDIDATE TECHNOLOGIES.

The coal and electric utility industries remain strong critics of the utility and costs of stack scrubber equipment. They site the obvious complaints of the high capital and maintenace costs and the scrubber sludge disposal problems. Now is the time to take their concerns to heart and offer them support for finding a cheaper and more efficient means of achieving the "Percentage Reduction" requirements of the Clean Air Act. Coupling coal washing to the LIMB technology is only one means of further reducing emissions from a stand alone technology. Since the standard for high sulfur coal is 90% SO_2 removal under the NSPS, that is the mark which candidate proposals should have to achieve or improve upon. Any improvements above 90% removal should be encouraged up to the limits of the funds available but should not represent the bulk of committed research dollars.

6. THE SECOND HIGHEST PRIORITY SHOULD GO TO THOSE TECHNOLOGIES DESIGNED TO RETROFIT EXISTING EQUIPMENT WHILE ACHIEVING AT LEAST 70% REDUCTION OF SO_2 AND NO_x EMISSIONS.

Mr. Chairman, the economics of the electric utility industry in the U.S. have changed dramatically in some regions of the Nation over the past ten years. Traditional doubling of demand each decade has shrunken to less than 2% annual growth in electricity demand almost over night. This has placed an overwhelming financial burden on those companies heavily capitalizing in huge nuclear and coal base load generators while its electricity market evaporates. For some, this has meant a complete restructuring in their planning and load management. Now, companies are looking to hold onto existing units beyond their normal book life in order to save capital while revenues are plummeting or debt service costs escalate. That is a fundamental flaw in our Nation's plan to steadily improve on air quality because it was predicated on the understanding that companies would gradually retire the old and dirty boilers and replace them with New Source Performance Standard regulated equipment.

When I brought this complaint to an Energy and Commerce Subcommittee in February, I called for the imposition of National Guidelines on the retrofit of old electric utility and industrial boilers. Electric utility company representatives on our panel concurred with that view. They reason that the retrofit investment may be threatened if the Congress comes up behind them with an acid rain control measure which requires further retrofit for pollution control equipment.

The West Germans have defined a new catagory of existing and polluting boilers which must be cleaned up if they operate beyond a predetermined number of hours. Thus, a boiler operator could spread the allowed remaining hours of operation over a long period of time without modifying its pollution control capability but it would have to make those investments if it wanted to operate the units beyond that imposed limit. That would give the boiler operator the option to plan its retirement or its future in the context of operating finances and need for rate increases.

Fluidized-bed retrofit of existing units are being planned and researched at the present time and their success will offer huge returns to the coal user market. But, the costs may be quite high on a per-kilowatt of installed capacity basis. Whether it is flu-bed, LIMB, or another type of boiler modification, it is a lucrative market for vendors and the target boilers are caught up in the E.P.A.'s tall stacks rule-making procedure. Many of those units have been included in the acid rain legislation considered by Chairman Henry Waxman in the 98th Congress markup of acid rain legislation. Whatever the rationale, the retrofit of old and dirty boilers must get attention in the Clean Coal Program because 25% of the Nation's boiler capacity will be 25 years or older by 1990. By the year 2000 that number will exceed 50%. The acid rain problem will not go away, as the coal industry has boasted, as long as the emissions from those older units are not reduced. This Congress must face that reality. The acid rain battle cannot be won by attrition.

7. CANDIDATE TECHNOLOGIES SHOULD HAVE NO MORE THAN A 24 TO 36 MONTH STARTUP AND SHAKEDOWN SCHEDULE.

This is a difficult criterion to establish with assurance that it will force efficiency into the Clean Coal program. However, it should be a consdieration in any strategy which accounts for the urgency of complying with the tall stacks regulation when it is finally adopted and promotes technologies already moving down the path towards commercialization. This is not the time to begin conceptual work on pollution control technologies. We must improve on what we now have and get them ready for commercialization as soon as possible. That will not cause us to back away from the more frontier oriented research on the drawing boards and in the pilot stage. They should proceed but their timed arrival does not fit the more pressing needs of the coal customers today.

8. ONLY THOSE TECHNOLOGY RESEARCH PROJECTS WHICH MOVE DESIGNS FROM THE PILOT STAGE OR, PREFERRABLY, THE PRE-SCALEUP STAGE TO THE READY-FOR-COMMERCIAL-USE PHASE SHOULD BE CONSIDERED IN THE FIRST THREE YEARS OF THE PROGRAM.

This is a reiteration of the point made above. There will not be the long-term funding needs committed to Clean Coal candidates which have not already passed several thresholds in its research life. A great deal of time, talent and money have already been invested in this area of research.

Reinventing what we already know may create jobs for consultants and engineers but this Nation's fiscal budget cannot afford that approach and the public deserves better planning and higher goals from the Clean Coal Technologies Reserve.

9. WASTE DISPOSAL RESEARCH SHOULD BE GIVEN A HIGH PRIORITY.

The enactment of the Resource Conservation and Recovery Act and the debate over reauthorization of the Superfund law have raised a tremendous amount of awareness about the serious problems we face in controlling toxic runoff from the piles of hazardous wastes being dumped upon the land. Whether it is stack gas scrubber sludge, wastes from a coal cleaning plant or disposal of fly ash and the spent-bed material from a fluidized-bed coal boiler, each residue has its own particular hazards and requires special disposal procedures to assure that pollution control equipment does not create a new wave of pollution problems. Fortunately, the Japanese and Europeans are wrestling with similar problems and there is a growing list of options for utilizing those wastes by treatment or recylcing rather than disposal into the land. The enforcement of RCRA and Superfund laws should not be a threat to the utility and industrial sectors. They will find that the liquid and solid wastes have potential for raising new revenue if special attention is given to finding those methods of treating the wastes and marketing them for profit.

Mr. Chairman, before I conclude my statement, let me reiterate our commitment to winning federal funding for a carefully designed and goal-specific Clean Coal Program. We believe that sufficient political interest will be drawn to a plan which focuses upon the research of coal boiler emission reductions. Those legislators frustrated by the 99th Congress' faltering on the enactment of the Clean Air Act reauthorization can push for adequate appropriations because the increased federal spending will have a direct benefit to their constituents living downwind of the millions of tons of sulfur dioxide and nitrogen oxides spewing from Midwestern coal-burning power plants.

As the successful demonstration of these clean coal technologies point the way to cheaper and cleaner air pollution control options, those same legislators will find it easier to convince the Congress that the Nation can cut its air pollution levels in half. Meanwhile, industry's increasing dependence upon our most abundant domestic fuel supply - the more than 150 billion tons of readily recoverable coal- can be accommodated without causing the environmental damage which threatens to blunt the potential for using more coal.

Mr. **Boucher**. Thank you, Mr. McCormick. That is a very encouraging and very thoughtful statement, and we appreciate it very much.

Mr. Wootten, we welcome you here, and note in passing that your company, Peabody, is the largest coal producer in the United States. I would assume that your largest customer is the electric utility industry. Would I be correct in that assumption?

Mr. **Wootten**. Yes; approximately 96 percent of our 65 million tons goes to the utility industry.

Mr. **Boucher**. Do you have within Peabody Holding Co. a division that conducts combustion or precombustion research and development?

Mr. **Wootten**. Yes; within the Holding Co. we have a function, the research and technology function, which I head up, and the concerted effort is involved in a number of projects. Right now we are committed to the TVA project, we are committed to the Colorado Ute project, and we have committed to the Public Service of Indiana sorbent injection project. Both of the last two are projects which have been submitted for consideration as clean coal technologies. We are also evaluating participation in some four other projects involved there. So, yes, we are trying to use our resources, limited as they are, to in fact enhance these sort of projects.

Mr. **Boucher**. Can you tell us the approximate budget for combustion or precombustion research that your company has every year, if that is not proprietary?

Mr. **Wootten**. It is approximately in the million dollar range. It will climb as these projects that we have committed to come into being and the expenditure cycles demand more and more input.

Mr. **Boucher**. And that is research you conduct in-house?

Mr. **Wootten**. Well, this is contracted research or participation with others. We don't have any actual in-house combustion capabilities.

Mr. **Boucher**. You contract with universities?

Mr. **Wootten**. Yes; we are involved with M.I.T., and there is a group within the State of Illinois called the Center for Research of Sulfur In Coal.

Mr. **Boucher**. Can you give me some indication—and I would ask Mr. McCormick to comment on this as well—of which of the emerging clean coal technologies have the potential for providing the most rapid benefit to the electric utility industry?

Mr. **Wootten**. Well, let me give you my perception, and I would have to speak as a Peabody representative, not a Coalition representative, because there are varied interests and there would be varied outlooks from the Coalition. But in looking at that I think you have two significantly different approaches. One is the retrofit problem that may be necessitated by controls placed on existing units. Those types of uses would force one into looking at those technologies that could be put in place with less difficulty at a lower cost and with a comparable environmental benefit to the technologies we have today, which primarily are fuel switching and the addition of flue gas desulfurization devices. Both have either cost or some socioeconomic impacts.

I think LIMB, which EPA has already began a demonstration of, is a very good one. As Mr. McCormick indicated, that is on one type of boiler. There are LIMB applications that would be appropriate on other types of boilers. It is the applicability to the boiler family that the technology might serve which is important.

Absorbent injection is another one. Most of the major utility installations are equipped with particulate control devices. We may somehow combine sulfur removal such that those particulate control devices become the ultimate collector. Basically you take some lime-based substance, inject it, it reacts with the sulfur and you produce a particulate. The sulfur gas by going to a particulate, you can collect the particulate with existing equipment. That would be an easy application. There are other dry scrubbing techniques that could be maximized the same way.

That would be one application. Coal preparation would be another area. If we can find better ways to go at coal preparation, we may be able to in some circumstances, depending on the amount of reduction that is required, be able to maximize our efforts there. It is conceivable that you could begin to look at a coal preparation plant as a refinery, where you would take one product of a certain quality and it would go to one setting where the environmental constraints would be more stringent, maybe an urban setting; and you may be able to go to a rural setting with another quality where the regulations would maybe not have to be so tight. We have some limitations there based on the type of sulfur that is in coal, whether it be organic or pyritic, and what we can do in the form of transportation. So there are some limitations there.

We are looking at a project, the Northern States Power project where they are going to retrofit fluidized bed combustion to an existing power plant. Actually cut the bottom out of it. That is a technology that is being done today.

What is not being done, and I think is important in a number of these areas, is to test other coal. The coal that is being fed into Northern States Power is a Western subbituminous coal. Midwestern coals or Eastern coals should also be tested in that facility, as well as in the Colorado Ute facility. The TVA facility is designed for Midwestern coal, but there are probably other coals to be tested. I think the moneys that are in the clean coal technology are for expanding the data base. Private industry has already said these are technologies we are going to develop. But the Midwestern utility sector would like to know, all right, what does that do to the type of coals that we have? It is somewhat of a regional issue, but I don't think it is exactly as Mr. Vaughan described it.

In the case of new systems, fluidized bed is one. We are looking at new coal gasification techniques, some of them that incorporate a second phase from the cool water project where we look at a gas turbine, a hot gas cleanup system, and a fixed bed gasifier. There are many of those that are going to, in fact, represent better ways to install capacity to meet a limited amount of demand. Whereas normal economics would say install a 600 megawatt facility, your demand may not support that; and therefore, your return from your utility commission may not support it, either, and you may want to put in a 100 megawatt block. Well, right now you cannot use coal in that sort of an installation. So coal would be locked out of that market if we don't do something to advance that technology. If that technology needs to be put in place commercially in the mid-1990's, I tried to point out to you that we have to begin that today.

I would stop there and let Mr. McCormick respond.

Mr. **Boucher**. Thank you.

Mr. McCormick, would you care to comment?

Mr. **McCormick**. There isn't much I can add to what was a very excellent answer, Mr. Chairman. But if you are stressing what are the most immediate technologies, then I would like to add one thing, and that is that we can combine some of the processes that we now have a lot of experience with. For instance, cleaning coal more thoroughly reduces the load on a LIMB-retrofitted boiler. I think we can start looking at some of these combinations, and that might be the only addition I would make to Mr. Wootten's statement.

Mr. **Boucher**. I assume that the boiler efficiency and the boiler life could be improved if the coal were washed in a better way before the LIMB technology used that coal. Is that correct?

Mr. **McCormick**. I think the American Electric Power Co. has proven that to itself. That it adds something like 10 percent to its on-line capacity by removing more of the ash from the coal, thereby cutting down on the wear and tear of the boiler.

Mr. **Boucher**. Well, I gather from your answers that there are a variety of emerging coal technologies that can be useful and can be implemented by the electric power industry rather quickly and would help meet the growing demand which you have forecast.

What level of funding should we be looking at for fiscal year 1986 to assist in the commercialization of those technologies?

Mr. **Wootten**. Well, first of all I think what Congress has to send to the industrial sector is a significant commitment that they are willing to follow through on this. I think the private sector has sent a signal back to Congress through DOE that they are willing to commit a substantial amount of their funds. If Congress can now find a way to respond to that with a meaningful amount of money, I don't think we are talking about $10 or $20 million, I think we are talking about hundreds of millions of dollars.

Now, Mr. Chairman, whether that has to be spent all in fiscal year 1986 is not certain. There is generally with projects an expenditure cycle where you begin slowly, you build in the middle years, and then you tail out with the testing phase. Maybe that should be looked at. But the first thing that has to happen is that there has to be a significant amount of money put forward to ensure that industry feels confident that you will go ahead so that they will, in fact, begin and commit these funds. Their own funds.

Mr. **Boucher**. Mr. McCormick.

Mr. **McCormick**. Mr. Chairman, I would say before we try to decide on an amount of money I think we ought first to decide on an authorization. I think the Appropriations Committee might deserve to hear from this committee and perhaps the Energy and Commerce Committee just what you consider ought to be the goals, and then decide how much money would be needed to attain that.

But if you held that a Federal-private cost-sharing ratio of something like 30-70, and I think I heard that figure discussed this morning, then you could leverage $100 million quite a long way. But I would say that if there isn't some authorization legislation preceding an appropriations number, then I think the Appropriations Committee will find it difficult to approve it.

Mr. **Boucher**. Mr. Wootten.

Mr. **Wootten**. I would try to echo Mr. Eric Reichl's statement that depending on the technology there may be a different formula for what is acceptable participation and what is not. I think the amount of risk in each of these technologies warrants some consideration. Also, the magnitude of the expenditure on the cycle. It may be a $20 million proposition to retrofit a boiler with LIMB technology, but it may be a $500 million proposition to build a new second generation combined-cycle utility system. So, if I could pose upon you to think that through, there would be quite a different formula, maybe, for the large expenditure than there would be for the smaller expenditure.

Mr. **Boucher**. I guess Congress is going to have to face this year assuming that the judgment is made to provide a demonstration scale cost-sharing program. The determination is going to have to be reached with regard to the level of funding, and that determination will need to be reached fairly quickly. The fiscal year begins in October.

Mr. Mannella had suggested an initial funding level of about $200 million. Is that in the right ballpark do you think?

Mr. **Wootten**. Yes, I would think so. I think a way to get a good handle on that, if Secretary Vaughan and the Department's efforts of going in and categorizing the 175 or 177 demonstrations could be done. If they could be forced upon to do that quickly, I think that the wheat could be cut from the chaff very quickly and you could begin, then, to get a feel in those technology areas about how much moneys would be needed to demonstrate them.

I don't think it is $8 billion—was it $8 billion that he stated—but I think that characterization could be done fairly quickly if they were forced.

Mr. **Boucher**. Mr. McCormick, do you want to comment further on that?

Mr. **McCormick**. Well, I am sort of still hovering around the $100 million range but I am not sure why. I also see this as a multiyear program.

Mr. **Boucher**. It is.

Mr. **McCormick**. And I think it is in the out-years that we will see the larger spending. So again I go back to let's design the corral before we decide how many horses we will put in it.

Mr. **Boucher**. Assuming that Congress does make the judgment to provide this program and provides funding for the 1986 fiscal year, what kind of structure would you contemplate the Department of Energy establishing for the purpose of evaluating the projects and making awards? Would there be a call by the Department on the private sector to offer advice, and should that be institutionalized in some way? Should we, perhaps, call on the National Coal Council for its recommendations in that regard? What general comments do you have in response to that question?

Mr. Wootten.

Mr. **Wootten**. The one of management, of how you implement actually selection of those projects is an important one. I think there is considerable expertise both in the National Coal Council in

DOE and in the private sector, and there may be mechanisms to bring that together as long as that implementation helped to expedite it and did not become another layer. I think you know what I mean.

I think that there are some of these technologies in some of the responses that are obvious and clearly are things that are right on the threshold and moneys could be expended fairly easily. The Department of Energy could act as a means to funnel those moneys to them much as they have with TVA and some other projects, full-scale demonstration projects. Other projects, because of their stage of development, may require some kind of competitive situation and evaluation because there may be more than one technology, there may be the conditions of needing to evaluate not only the technology part of it but the data base and whether the proposers have the substance to carry through their plans. So that may take a different approach, and that, in fact, may take a blue ribbon council of some kind or those kind of ideas.

I think that is something that our Coalition is going to try to give some thought.

Mr. BOUCHER. Very good.

Mr. MCCORMICK. Mr. Chairman, if the Congress is very emphatic about the goals of this program, if it is going to lay out that money, and it makes the EPA an equal partner with DOE, then I think you are going to find a lot of the wheat and the chaff separating very quickly. Then if you add to that the EPRI and the National Coal Council, then I think you have the input from the four main players. And I don't think it would take more than a few weeks to come down with the first cut of the sensible list of candidates to get the first amounts of money.

Mr. BOUCHER. Thank you very much. I don't have any further questions. If neither of you cares to add anything further, that will conclude our testimony today.

I want to thank you very much for your very helpful presentation. I am personally very glad to see the interest that the panel of witnesses has expressed in developing a Federal role in support of demonstration-scale facilities for emerging clean coal technologies. I am glad to see that there is substantial support here on this subcommittee for that as well. And I, for one, am very hopeful that Congress will approve a program this year.

There being nothing further, the subcommittee is adjourned.

[Whereupon, at 12:50 p.m., the subcommittee was adjourned, to reconvene subject to the call of the Chair.]

APPENDIX I

ADDITIONAL STATEMENTS SUBMITTED FOR THE RECORD

STATEMENT OF
THE AMERICAN GAS ASSOCIATION
BEFORE THE
SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS
COMMITTEE ON SCIENCE AND TECHNOLOGY
UNITED STATES HOUSE OF REPRESENTATIVES
ON EMERGING CLEAN COAL TECHNOLOGIES

May 29, 1985

The American Gas Association (A.G.A.) is a national trade association comprising nearly 300 natural gas distribution and transmission companies serving more than 160 million consumers in all 50 states. Collectively, these companies account for nearly 85 percent of the nation's total annual gas utility sales.

A.G.A. is pleased to submit this statement on emerging clean coal technologies. Although we are not in a position to propose specific projects, we would like to be certain that this Subcommittee is aware of new technologies that could be funded from the Clean Coal Technology Reserve and that either: (a) combine the use of natural gas with coal to reduce emissions; or (b) otherwise help to utilize coal in a more environmentally attractive manner.

NECESSITY FOR FEDERAL INCENTIVES

In its Report to Congress on Emerging Clean Coal Technologies, the Department of Energy (DOE) recommended that the Federal Government should not provide incentives (i.e., loan guarantees, cost sharing, etc.) for emerging clean coal technologies. The DOE determined that free market forces will "select and commercialize the most efficient and environmentally-effective technologies for processing and using coal . . . ." The DOE further stated that Federal incentives would only interfere with the operation of market forces and could affect adversely the development of nonsubsidized technologies.

A.G.A. does not believe that Federal incentives would interfere with the commercialization of these technologies. Although free market forces will ultimately determine which of the emerging coal technologies will be best suited for commercialization, substantial expenditures will be necessary to develop these technologies prior to commercialization. Federal incentives are necessary to develop and demonstrate the potential for these new technologies: i.e., to bring them to the point at which the market can choose between them.

As a related point, regulatory policies often constrain rate-regulated gas and electric utilities from gambling on a promising new technology. These regulated companies frequently need to share risks with governmental agencies until the new technology is proven through experience with pioneer plants.

A.G.A. also disagrees with the DOE's suggestion that past experiences with Federal assistance in the development of new fossil technologies has been completely unsuccessful. A recent and prominent example is the Cool Water plant in Daggett, California. This small-scale powerplant produces on-site medium BTU coal gas at a rate equivalent of 1000 barrels of crude oil per day for use in combined cycle power generation. Although Federally assisted, the project has reportedly been so successful that it is now emerging as a possible model for large-scale private sector efforts.

SELECT GAS USE

Select gas use (select use) refers to a relatively new concept in fuel combustion: the burning of natural gas with less environmentally attractive fuels in the same or separate combustion units for environmental control purposes. Natural gas combustion emits virtually no sulfur dioxide or particulate matter, and far less nitrogen oxides, nonmethane hydrocarbons and carbon monoxide than other fossil fuels.

As one option, select use may involve the combustion of gas and another fuel (most often coal) in the same combustion unit as a fuel mixture. A more common approach, and less difficult from an engineering perspective, involves the concurrent combustion of gas and some other fuel in separate combustion units, with subsequent averaging of the emissions from the two sources. This latter approach (termed a bubble), when approved by the Environmental Protection Agency (EPA), may be used to meet the air quality guidelines of a State Implementation Plan (SIP). A third approach (not currently sanctioned by the EPA) entails the seasonal substitution of gas for other fuels. Coal or high-sulfur oil could be burned for a portion of the year and natural gas could be burned for the remaining portion of the year to offset the coal- or oil-derived emissions.

These concepts have advanced from the theoretical stage to the implementation stage. More than two dozen select use applications have been implemented, including four cases of concurrent combustion in a single unit. Furthermore, at least four major institutions are conducting additional research into the simultaneous combustion of gas and other fuels in a single unit. The research relating to gas and coal combustion is focused in three areas: (1) reburn technology to reduce NO_x and SO_x emissions; (2) gas use to assist the burning of coal-water mixtures; and (3) gas use to assist oil-to-coal conversions (utilizing either coal-water or dry coal).

(1) Reburn Technology

Reburn is a post-combustion pollution control method that can be used to reduce NO_x levels found in the combustion products of coal-fired electric utility or industrial boilers. Natural gas (or another fuel) is injected into the exhaust from a coal-fired boiler, creating a fuel-rich zone in which the NO_x reacts and produces free nitrogen; air is then added to complete the combustion process. Preliminary testing indicates the reburn process using gas could easily reduce NO_2 emissions by 50 percent. The Gas Research Institute and the Energy and Environmental Research Corporation are currently conducting research on the reburn process to determine: (a) how close the reburning fuel should be relative to the combustion zone; and (b) how much time should be allowed for reburning before air is injected into the process.

(2) Assisting Coal-Water Mixtures

Coal-water mixtures were originally proposed as a way to displace foreign oil with domestic coal. More recently, however, it has become evident that coal-water mixtures may appeal to those who use coal but want to avoid the environmental impact associated with the direct combustion of dry coal. One reason for this expanded market for coal-water mixtures is that developers of such mixtures have been developing innovative methods for cleaning the coal before it is integrated into a mixture. Unfortunately, the use of coal-water mixtures may lead to substantial deratings, slagging, fouling, flame instability and other problems. Recent gas industry sponsored research indicates, however, that cofiring coal-water mixtures with natural gas offers an economic and environmentally attractive solution to these problems. We cite as examples three recent papers:

(1) J. Dooher, T. Kanabrocki, and D. Wright, Co-firing of Coal Water Slurries with Natural Gas, (Adelphi Center for Energy Studies, Adelphi University, Garden City, New York).

(2) Robert H. Essenhigh, E.G. Bailey, Kyu-il Han, and Zongwen Li, Performance Characteristics of a Hot-Wall Furnace Fired With Coal Water Slurry (CWS) Using Gas/Air Atomization (The Ohio State University, Columbus, Ohio).

(3) Alex E.S. Green, Coal-Water Mixtures - A Market Opportunity for Natural Gas (University of Florida, Gainesville, Florida).

(3) Oil to Coal Conversions

In addition to the use of coal-water mixtures, economically and environmentally advantageous conversions of oil-fired boilers to coal have been proposed using a precombustor/ash separator unit. A research team at the Unversity of Florida is currently using natural gas to assist a full scale oil to coal conversion. We cite for example:

(1) A.E.S. Green, An Alternative to Oil: Burning Coal with Gas (Gainesville, FL, University Presses of Florida, 1981).

COAL GASIFICATION

Gasified coal can be combusted without the adverse environmental impact associated with direct combustion of pulverized coal. A coal gasification plant gasifying western coal produces from 5 to 58 percent of the air pollutants emitted by a coal-fired electricity generation plant with scrubbers. Furthermore, a coal gas fication plant emits only 40 percent of the solid wastes produced by a coal-fired electricity generation plant.

Funds from the Clean Coal Technology Reserve could be used to promote second- and third-generation gasification processes. We view as particularly promising the U-Gas technology (which was developed by the Institute of Gas Technology and would have been demonstrated commercially if the Memphis onsite medium Btu coal gas project had received Federal assistance and become operational); the Kellogg-Rust Westinghouse (KRW) technology (which is currently being utilized at a Pennsylvania test facility that receives both industry and government support); and any other technology which entails ash agglomerating fluidized bed gasification.

It is the considered opinion of our Coal Gasification Subcommittee and Advanced Technology Task Group that these second-generation technologies -- when compared with the currently available Lurgi technology -- could potentially reduce unit production costs by at least 20 to 25 percent. In addition, our most knowledgeable member company advisory groups are convinced that second-generation technologies could also reduce substantially the environmental impact of currently available coal gasification technologies.

Additional research facilities for these technologies, such as a test facility that we propose to site at the Great Plains gasification plant, would be valuable. However, we also believe that the second-generation technologies are now ready to proceed to the stage of small-scale commercial projects.

PROJECT SELECTION PROCESS

The Environmental Policy Institute has suggested that funding recommendations for specific clean coal projects should be determined by the DOE, EPA, National Coal Council (NCC) and Electric Power Research Institute (EPRI). A.G.A. strenuously opposes the selection of coal projects by such an exclusive group of organizations. The NCC and EPRI represent narrowly focused interests whose primary research concerns may not encompass the vast array of clean coal technologies. For example, EPRI is concerned primarily with the development of coal technologies that can be used to generate electricity. Although we support clean coal research for electricity generation, we believe that clean coal research for purposes other than electricity generation would also serve the public interest. Research on select use and coal gasification would result in the development of both industrial and electric generation uses for coal that offer significant environmental benefits.

A.G.A. strongly recommends that decisions on specific coal projects be made by the appropriate government agencies and a broad-based consortium of energy research organizations representing all of the segments of the energy research community that are interested in clean coal research. A diverse group of organizations could determine by consensus the coal research that would most benefit the public.

CONCLUSION

A.G.A. believes that select gas use and advanced-generation coal gasification offer the potential for significant advances that will permit coal to be used in a clean, environmentally sound and cost-effective manner. We also believe that the process for selecting coal projects should reflect the consensus of the energy research community and the government on the coal research projects that would be in the public interest.

AMERICAN PUBLIC POWER ASSOCIATION

2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

May 7, 1985

The Honorable Don Fuqua
Chairman, Subcommittee on Energy Development
  and Applications
Committee on Science and Technology
U.S. House of Representatives
Rayburn House Office Building
Washington, D.C. 20515

Dear Congressman Fuqua:

The American Public Power Association would like to express its support for the Emerging Clean Coal Technologies program as described in Section 321 of the House Joint Resolution No. 648 of 1984. The reasons for our support are detailed below.

The American Public Power Association (APPA) is the national trade organization representing 1,750 local, publicly-owned electric utilities throughout the United States, Canada, Puerto Rico, the Virgin Islands, American Samoa, and Guam. Most APPA members are municipally-owned systems. About 600 public power systems generate electricity in addition to distributing it to consumers.

APPA endorses strengthened Federal support for the demonstration of emerging clean coal technologies for several reasons:

- First, coal is our most abundant domestic energy resource, for which increased utilization is in the national interest.

- Second, much of the electricity generated by APPA members occurs within municipal city limits or other areas of relatively high population density. For reasons of public acceptance and general public welfare, clean conversion technologies must be employed to foster the greater use of coal at these generating sites.

- Third, current technologies for controlling the air emissions from coal-fired generation of electricity impose other environmental burdens in solid waste disposal and may add as much as 25 percent to installed costs of new generation.

- And fourth, as you may be aware, the American Public Power Association supports a least-cost emission reduction program to control acid precipitation. In order to ensure the lowest long-term electricity costs to consumers, newer, less costly, and cleaner coal conversion technologies must be developed to balance future energy and environmental goals.

APPA believes there are emerging coal technologies that can promote these objectives. APPA recommends that due consideration be given to these technologies as the clean coal technology program evolves and receives funding.

Foremost on the list of promising technologies is fluidized-bed combustion (FBC). FBC offers fuel flexibility, rigorous emission control, a more easily handled solid waste, the potential for modular construction, and the ability to be retrofitted for existing boilers. To date, demonstration projects are planned by investor-owned electric utilities, rural electric cooperatives, and Federal systems. Yet due to its modular nature and ability to burn many wastes found at the local level (including municipal solid waste, certain forms of industrial or process wastes, or agricultural residues), FBC may be especially appropriate for municipal electric utilities.

Another approach to meeting the objectives of the Emerging Clean Coal Technologies program is to emphasize combined heat and power production with coal-fired capacity. Through such cogeneration, a greater amount of useful energy services are provided to the consumer for a given amount of fuel input. Combined heat and power production means that fixed costs and air emissions are spread over a larger output of useful energy, thereby acting to lower costs to consumers and to decrease emissions per unit of desired energy services.

Means to gasify coal -- either in combination with conventional boilers or with advanced technologies -- are notably appropriate for such applications. Examples include the use of gasified coal in district heating and cooling systems and in fuel cells. Both examples lend themselves well to cogeneration. APPA urges strong consideration of these approaches as well.

As the electric utility industry grapples with needed capacity additions over the coming decade against a backdrop of uncertainties in fuel availability and more stringent environmental controls, the demonstration of appropriate coal conversion technologies is a matter of national import. APPA urges support for the Emerging Clean Coal Technologies program. We encourage that support be matched with an appreciation for the needs and opportunities of public power systems that provide electricity to one in every seven Americans.

Sincerely yours,

Alex Radin

/da

HURLEY W. RUDD
MAYOR COMMISSIONER

JACK L. McLEAN, JR.
MAYOR PRO TEM COMMISSIONER

CAROL BELLAMY
COMMISSIONER

BETTY G. HARLEY
COMMISSIONER

FRANK VISCONTI
COMMISSIONER

DANIEL A. KLEMAN
CITY MANAGER

ROBERT B. INZER
CITY TREASURER-CLERK

STEVEN BORDELON
CITY AUDITOR

JAMES R. ENGLISH
CITY ATTORNEY

TELEPHONE
(904) 599-8100

CITY HALL
32301

May 6, 1985

Honorable Don Fuqua
Representative
U.S. Congress
2269 Rayburn House Office Building
Washington, D.C. 20515

Dear ~~Congressman~~ Don Fuqua:

Subject: City of Tallahassee's Testimony to
Subcommittee on Energy Development and
Applications

The City of Tallahassee is submitting the enclosed testimony to you as Chairman of the Committee on Science and Technology. This testimony is being submitted for the record to the Subcommittee on Energy Development and Applications in conjunction with the Subcommittee's hearings on May 8, 1985. Also, Tallahassee will be represented at the May 8, 1985, subcommittee hearings because of the importance your Clean Coal Technology Program is to Tallahassee and the nation.

Tallahassee is the only municipal system at this time involved in the Clean Coal Technology Program and we appreciate this opportunity to express the views of a municipally owned system.

Sincerely,

Dan

Daniel A. Kleman
City Manager

DAK/RTK/mgm

Enclosure

TESTIMONY SUBMITTED FOR THE RECORD TO THE SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS OF THE COMMITTEE ON SCIENCE AND TECHNOLOGY U. S. CONGRESS, WASHINGTON, D. C.

BY

THE CITY OF TALLAHASSEE
DANIEL A. KLEMAN, CITY MANAGER
MAY 8, 1985

Mr. CHAIRMAN, Members of the Subcommittee on Energy Development and Applications and Staff, the City of Tallahassee is pleased to present this testimony for the record on the Emerging Clean Coal Technology Program. The City of Tallahassee feels that the Emerging Clean Coal Technology Program is necessary in order to demonstrate new technology for power generation that is both cost effective and environmentally benign. If the Emerging Clean Coal Technology Program does not go forward, then new innovative technologies that would benefit society by reducing acid rain and foster the use of abundant domestic energy sources such as coal would not be demonstrated soon enough for at least the electric utility industry when they re-enter the marketplace for new apparatus in the early to mid-1990's.

During the mid-1970's, when motorists in the United States were introduced for the first time to dollar-a-gallon gas and long lines at the pumps, the public learned that this country had an energy crisis. Today, after nearly 10 years of rising prices and even more uncertain energy supplies, the crisis has drifted away from public thought. Today's concentration is on the economy: high interest rates, unemployment, low productivity and America's decline in the world marketplace. While many people fail to recognize a critical connection between the two topics, there is a key link; and it is America's ability to produce electricity, at a reasonable cost.

Much of the economic difficulty that confronts the power industry and the nation today has its roots in the rapid escalation of petroleum prices during the decade of the 70's. Thirty-six percent of all U.S. electrical generating capacity is oil or gas fired, equivalent to 2.6 million barrels of oil per day. About 40 percent of the oil and 80 percent of the natural gas used in the United States are for heating (space, water and industrial process heat), much of which can be done efficiently with electricity.

The United States depends on foreign sources to meet about 30 percent of its total oil demand. The economic impact of the oil consumed by electric utilities totaled approximately $13 billion in 1981. This is equivalent to 29 percent of imports from OPEC, and equal to approximately half our merchandise trade deficit for that year. To be competitive economically, the United States must utilize its coal resources. A 1980 survey of 44 U.S. utilities showed that coal maintained a dramatic cost advantage on a kwhr basis - 2.5 cents for coal, versus 5.4 cents for oil. In spite of this domestic advantage, however, we continue to rely on higher-priced, foreign fuels. With deregulation of natural gas pricing, gas, which is a substitute fuel for many other uses, is expected to reach a value close to oil in five to ten years.

Fluidized bed combustion can provide utilities the ability to fire U.S. coal while keeping the costs for environmental compliance under control. We believe the fluidized bed combustion system, in comparing it to a pulverized coal boiler with fuel gas desulfurization (FGD), would offer the following advantages to the utility industry:

1. Reduced ash/waste disposal quantities.
2. Superior ash physical, chemical and leeching properties.
3. Reduce fuel preparation requirements.
4. Flexibility to burn variable quality fuels.
5. Reduce NOX emissions.
6. Improve economics, both capital and operating.
7. Eliminates the need for dry or wet FGD systems.
8. Chlorine and fluorine compounds are largely retained in the ash.
9. More siting flexibility since FGD systems are not required.

In our opinion, the Emerging Clean Coal Technology Program is necessary to demonstrate the circulating fluidized bed boiler technology since it has not been demonstrated at this size previously. The risk associated for a small municipal utility to proceed with innovative technology that could possibly provide us with the advantages stated previously is much greater than what we can afford to take on by ourselves, especially when this technology, once demonstrated, would have wide application to all other generating utilities due to the size of the boiler and quality of coal that would be demonstrated through our project and other innovative technologies that have been proposed. The role of the Federal Government in assisting the private sector in bringing to the commercial forefront new technology by federal incentives, including grants, loan guarantees, low interest loans or price supports is vital when you consider the significant benefit to our society from these technologies. In addition, the reasons for the development of new and innovative technologies as were recommended in the Emerging Clean Coal Technology Program is based on the overall impact on society in the areas of environmental protection as mandated by federal EPA regulations, national energy security and quality of life in general.

The circulating fluidized bed (CFB) technology offers several unique advantages over bubbling fluidized bed (BFB) technology:

The CFB can burn a wider variety of fuels including coals with high sulfur and high ash contents, lignite, peat, wood, bark, petroleum coke and other refinery residues. Typically, many of these fuels are difficult and/or uneconomical to burn in BFB systems. The CFB also has sufficient flexibility to burn different types of fuels in the same combustor. This fact reduces dependency on oil.

Higher carbon burn-out (over 99%) can be achieved for all fuels including those with low heating values and/or low proportion of volatiles.

Higher degree of desulfurization can be achieved. Over 90% SO2 removal can be obtained with a calcium-to-sulfur (Ca/S) molar ratio of 1.5.

Lower NOX emissions (less than 300 volumetric parts per million, vppm) can be obtained through "staging" the combustion air. This responds to the overall objective of improving the quality of the air.

Higher carbon burn-out (combustion efficiency) and the lower consumption of limestone required for desulfurization contributing to higher overall thermal efficiencies (90-92% based on the lower heating value).

CFB's offer simpler fuel preparation and feed systems.

The CFB is clearly a very versatile system which can be used for thermal energy production in industry, and for electricity production in utility power plants and cogeneration plants.

In summary, CFB combustion is very effective in situations where hard-to-burn and/or low grade fuels are to be utilized, where strict environmental control is required, and where an efficient and flexible operation is required.

The City of Tallahassee submitted to the U.S. Department of Enrgy a Statement of Interest for our Arvah B. Hopkins Generating Station, Unit #2 for a circulating fluidized bed replacement boiler, with reheat. Our proposed circulating fluidized bed combustion boiler would utilize 640,000 tons of high sulfur eastern coal per year producing 235 megawatts of power. In addition, a life extension and uprating would be conducted on the existing turbine generators which could produce an additional 5% to 15% of additional megawatts.

Therefore, we feel the Emerging Clean Coal Technology Program must go forward and cover several areas of innovative technology to be demonstrated. In our opinion, we feel one of these technologies should be circulating fluidized bed combustion based in the advantages and merits as discussed above.

Transamerica
Delaval

STATEMENT BY

Bern E. Deichmann

Vice President, Marketing

Transamerica Delaval, Inc.

Hearing on Clean Coal Technology

**Transamerica
Delaval**

I am Bern E. Deichmann, Vice President of Marketing for Transamerica Delaval Inc. Transamerica Delaval is headquartered in Lawrenceville, New Jersey and has manufacturing facilities at 20 locations in the United States and overseas.

We are most grateful for the opportunity to testify on behalf of the Clean Coal Technology program and to acquaint the Committee with our proposal. We believe strongly in the necessity to accelerate the wise, efficient and clean use of our coal reserves. We joined the Clean Coal Technology Coalition to assist the Congress in this, and we fully endorse their statement of support.

The overall objectives of our Coal Gas Diesel (CGD) program are the timely research, development and verification testing needed to achieve:

1. OVERALL EFFICIENCY GREATER THAN 50% (coal pile to bus bar)
2. COST OF ELECTRICITY LESS THAN THAT FOR COAL FIRE CONVENTIONAL STEAM PLANTS WITH FLUE GAS DESULFURIZATION.
3. EMISSION OF ATMOSPHERIC POLLUTANTS WITHIN LIMITS SET BY FEDERAL STANDARDS.
4. FULLY DEVELOPED AND COMMERCIALLY AVAILABLE BY THE 1990'S.

These objectives are realistic; the technology can be applied and verified; hardware modifications are within the current state of the art; the economics are real and attractive; and the need is great. To accomplish these objectives a pilot plant consisting of the following major components is required: (See Schematic I attached)

1. LOW BTU GASIFIER.
2. GAS CLEAN UP SYSTEM
3. A MEDIUM SPEED, DUAL FUEL ENGINE SYSTEM.
4. WASTE HEAT RECOVERY SYSTEMS.

Transamerica Delaval proposes to study, develop and test a system that will provide an economical way to burn coal cleanly. We propose to build a full scale pilot plant to demonstrate the technology, the economics and the low enviromental impact. The testing proposed will be phased from burning cold clean Low BTU coal gas at the start and moved toward burning hot dirty gas. The objective is to determine how hot and how dirty the gas can be for the engine to burn it economically and still meet all environmental criteria.

We propose that a dual-fuel, heavy-duty medium-speed diesel engine of proven design be employed, driving a generator to produce electricity, fueled by low BTU gas produced from coal.

The developmental aspects of our proposal are in two principal areas: FIRST, apply the most modern, cost-effective technology to remove sulfur and other pollutants from the produced gas so that the atmosphere remains clean, and SECOND, developing the necessary modifications to the engine to most efficiently burn the low-BTU fuel and achieve the maximum power rating.

We believe the proposal we have submitted will lead to the mitigation of acid rain as more coal is burned in the future by utilities and industry. At the same time, our proposed plant will:

1. Provide measureable savings in fuel consumed per unit of electricity generated,

2. Rationalize the expenditure of capital to meet electrical needs of industry and smaller communities

3. Shorten lead times for construction to twenty-four months or less.

We believe our experience in burning medium BTU sewage gases particularly well qualifies us to undertake this development and we are confident of our ability to execute the program within the time and cost constraints we have offered.

Transamerica Delaval has been performing preliminary research and has found its engine has the ability to burn low-Btu gas. The test program was conducted at our facility in Oakland, California early in 1984 and the gas was a simulated gas. Combustion characteristics and results were excellent.

We also conducted preliminary testing of coal tars produced from a Utah coal. The results of the tests were most encouraging. With additional R&D and improvements in components, our engine will be able to utilize both the gas and the tars of a gasifier and convert them to electrical energy.

Concerning sulfur removal, we propose working with a company having broad experience in this field to develop a commercial gas purification unit to incorporate into the total gasification and heat engine system.

With regard to the market for such a system, there is an increasing trend toward smaller power plants to service the industrial and utility sectors. Some conclusions from studies are:

1. Large, conventional, coal-fired plants are costly due to

excessivley long design, permitting, and construction times, as well as stringent environmental controls.

2. Regulatory control making it difficult to incorporate all costs into the rate base.

3. Studies show that small units can be very competitive because:

   A. -They can be factory-built and modularized.

   B. -Utilize cogeneration to boost plant efficiencies.

   C. -Technology has improved the performance of older methods of power production, such as diesel engines, and of clean up systems associated with them.

As noted previously, when it is demonstrated in this program that a large bore, medium speed diesel engine can be run economically in an environmentally sound way on cold, clean, low BTU gas from a coal gasifier, we propose further research to expand the envelope from burning cold, clean gas toward establishing the limits of burning hot, dirty gas. Thus simplifying the total facility and improving the economic evaluation.

This phase of the project includes the study, development and testing of:

1. Improved gas clean up technologies.

2. Improved emissions control technologies for diesel engines.

3. Advanced materials for diesel engines.

4. Improved gasifier technologies.

As you can see, this program seeks to build a strong technology base for the utilization of coal-derived fuels.

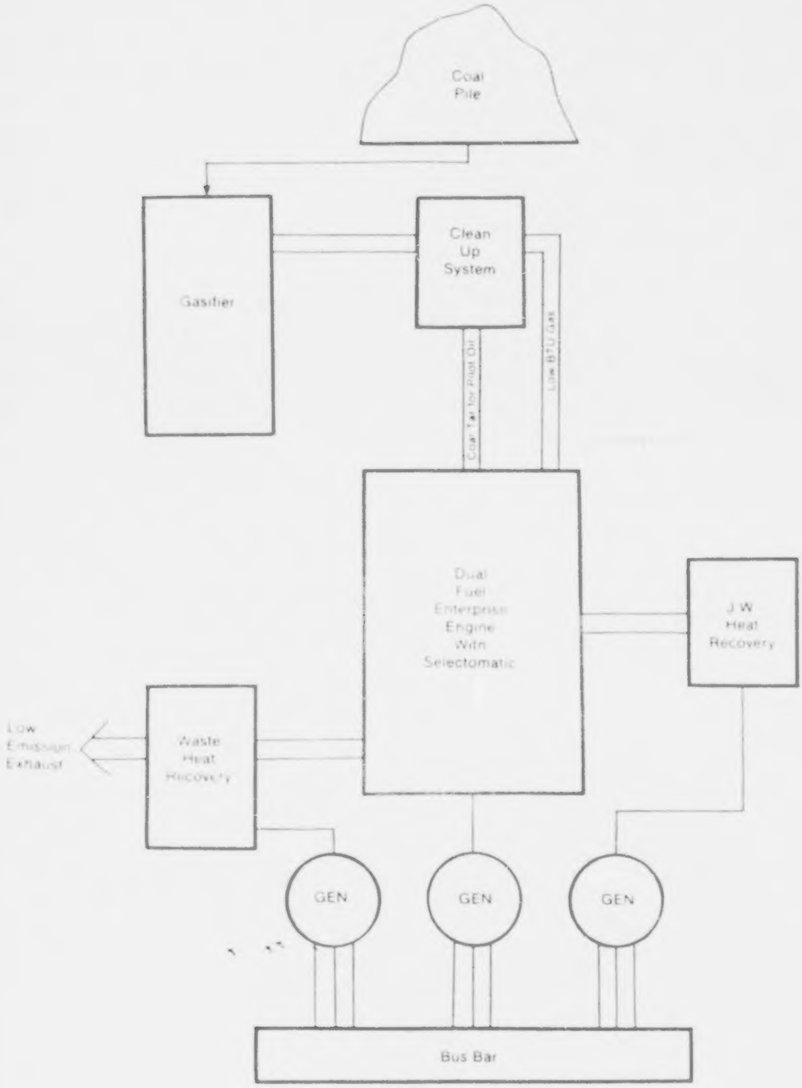
Without a strong federal role supporting fuel utilization technology, advanced heat engine capabilities will be slow in developing and there will be less incentive to bring these fuels to the marketplace. Such an approach would be a costly strategic error, probably delaying the penetration of coal-derived fuels into the petroleum market for many years.

The most effective approach for accomplishing the objectives is to heavily involve industry in all the technology programs but to rely on Government funding for basic and applied technology development and to support high cost experimental facilities. This approach will provide for a wide range of technology options and is expected to reduce costs and accelerate market entry of the systems.

In summary, Transamerica Delaval proposes to study, develop and test a full scale pilot plant that will provide an economical way for industry and utilities to burn coal cleanly. The result will be a pilot plant to demonstrate the technology, the integration of component systems, the economics and low enviromental impact for industries and utilities as they continue a transition to coal - a fuel that is not only more abundant than almost any other fossil fuel but one that reduces our dependence on foreign countries. This project will be a joint venture between the Federal government and industrial partners, and one that will provide a good return on investment for all of the participants.

Thank you

Transamerica Delaval Inc. Presents To The Department Of Energy A Clean Coal Technology Program


Coal Pile
Gasifier
Clean Up System
Coal Tar for Pilot Oil
Low BTU Gas
Dual Fuel Enterprise Engine With Selectomatic
J.W. Heat Recovery
Low Emission Exhaust
Waste Heat Recovery
GEN
GEN
GEN
Bus Bar

Coal to Bus Bar Efficiency 50%

THOMAS R. KUHN, Executive Vice President

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
Washington, D.C. 20036-[illegible]
Tel. (202) 828-7400

May 29, 1985

The Honorable Don Fuqua
Chairman
House Science & Technology Committee
House of Representatives
2321 Rayburn House Office Building
Washington, DC 20515

Don
Dear ~~Mr. Chairman~~:

I appreciate the opportunity to submit the enclosed testimony regarding the clean coal technology reserve on behalf of the members of the Edison Electric Institute (EEI).

EEI is the association of electric companies. Its members serve 96% of all customers served by the investor-owned segment of the industry. They generate approximately 75% of all electricity in the country and service 73% of all ultimate customers in the nation. We support the clean coal program and ask that the following statement be made part of your hearing record.

Sincerely,

Tom

Thomas R. Kuhn

TRK:llj
Enclosure

CLEAN COAL TECHNOLOGY RESERVE
A NATIONAL PRIORITY

SUBMITTED BY

THE EDISON ELECTRIC INSTITUTE

TO THE

SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS

HOUSE COMMITTEE ON SCIENCE AND TECHNOLOGY

CLEAN COAL TECHNOLOGY RESERVE

A NATIONAL PRIORITY

On behalf of the Edison Electric Institute (EEI), we welcome the opportunity to discuss the potential role of clean coal technologies as a supply option to provide for the continually growing demand for electricity. EEI is the association of electric companies. Its members serve 96 percent of all customers served by the investor-owned segment of the industry. They generate approximately 75 percent of all electricity in the country and service 73 percent of all ultimate customers in the nation. We appreciate the willingness of the Committee to conduct this timely and important hearing.

SUMMARY

The evolution of the forces affecting utility planning has made the characteristics of the alternative clean coal technologies of great interest. Current circumstances, however, may prevent full utilization of the benefits which these technologies offer.

During my testimony today I will describe the need for new capacity, the resource options being implemented to balance supply and demand, the investment planning considerations, and other technology options available to electric utilities. The advantages of using clean coal technologies to advance the list of generating options for providing power in the future include:

- Environmental benefits of reduced SO_x, NO_x and particulate removal on a cost-effective basis
- Modular Construction
- Wider Fuel Selection
- Improved Efficiency and Availability
- Greater Coal Utilization

This program provides a unique opportunity for technology to drive regulation based upon marketplace rather than regulatory criteria. As an incremental investment banker in these projects, the federal government has a unique opportunity to reduce the risk of technology demonstrations.

NEED FOR NEW CAPACITY

The past 15 years have been tumultuous ones for energy and electricity. Twice, oil imports were curtailed--first, by the embargoes and second, by the Iranian revolution. Also, we should not forget that during the mid-1970's natural gas curtailments led to unemployment. The promise of nuclear power has been tarnished by well-publicized problems affecting some plants. And, of course we all know what happened to prices of all forms of energy. These events reduced economic growth, contributed to the changing structure of the economy, and affected our personal behavior and attitudes.

Now, because we appear to be in a period of energy stability, there is a danger of complacency. Oil, natural gas, and coal supplies are abundant and market prices soft. For most electric utilities, construction programs are coming to an end. In addition, new electricity supply sources and demand side management are growing. It is unlikely that we will return to former use patterns and high consumption growth.

However, this appearance of stability offers little solace to electric utility planners. Because more moderate growth continues and because construction leadtimes in this industry are so long, difficult planning decisions for adequate power supplies in the 1990's must be made soon. New capacity is needed to support economic growth, to provide for retirement of plants, and to reduce dependence on oil and gas.

Virtually all forecasters expect continued growth in electricity demand. Most long-run forecasts for electricity consumption growth fall in a range of 2.0 to 4.0 percent per year. The electric utility industry is planning for growth in consumption of 2.7 percent and growth in peak demand of 2.5 percent over the next decade. This implies a 30 percent increase in consumption over that period. These growth rates, although low by long-run historical standards, represent a continuation of the relative growth trends of energy and electricity. Since the oil embargo, annual total energy use has actually declined while electricity sales have risen 34 percent over this 12 year period.

The fraction of energy use accounted for by electricity will continue to grow. In 1950 electricity accounted for 15 percent of total energy use. By 1960 the share was 19 percent. As we reached 1970 and 1980 it rose to 24 percent and 33 percent respectively. The share is expected to rise to over 40 percent in the 1990's. Coal's contribution to electricity production is also expected to increase.

As plants grow older, just like any industrial facility, they must be replaced. With fewer new plants coming on line, the average age of facilities in place will be rising throughout the balance of the 1980's. While the effects of aging can be mitigated by appropriate investments and plant-life can be extended in some cases, the plants must ultimately be replaced.

In some cases new capacity is also needed in order to reduce dependence on high-cost oil and gas, especially imported oil. Since the 1973 embargo, electric utilities have reduced oil consumption by over 50 percent and gas consumption by 20 percent. Most energy analysts agree that utilities should continue to work toward becoming less dependent on these high-cost fuels.

Not only is there a consensus that new capacity is needed, there is also wide agreement about when it will be needed. Approximately 131 gigawatts (GW) of generating capacity are planned to come on line from 1984 to 1993. This is equivalent to approximately one new large plant each and every month for the next ten years. Even with this expansion program, sometime in the early 1990's peak electricity demand is expected to exceed installed capacity.

We concur with the conclusions drawn by the Department of Energy in publication DOE/IE0003, Staff Report Power Supply and Demand for the Contiguous United States 1984-1993. This publication states that there is "potential for inadequate power supply in some regions" during the 1991-93 period even assuming all planned capacity is brought on-line as scheduled.

Without question, uncertainties surround all of the factors affecting the need for new capacity. Yet, projecting a plausible range of very modest growth rates and projecting a minimum level of replacement of aging and high-cost facilities, some new capacity above and beyond what is already planned will be required in the 1990 to 1995 timeframe. There is a continuing need for new generating plants and the critical planning focus is now on the early 1990's.

Utility Investment Planning Considerations

The economic and regulatory environment in which utilities operate affect the choice of resource options which will be selected to meet this need for new capacity. Conditions today favor selection of technologies with certain characteristics.

Expectations are for electricity sales to grow near or slightly below the growth of the economy. Although some years will exhibit strong growth (for example, sales were up 5.6 percent in 1984), new capacity will need to be added at a slower rate than in the past. For many utilities, increments of new demand are smaller. The first implication is that needed increments of supply are smaller, as well. A second implication is that a planning error on the high side is not quickly corrected by high growth. A given increase in supply takes longer to be absorbed by growing demand than in the past. Nor can a planning error on the low side be quickly corrected. Consequently, increments in supply should closely match increments in demand.

The cost characteristics of generating electricity today reinforce this point. Previously, the addition of a new generating plant actually lowered the unit cost of electricity. Productivity improvements and learning curve effects made economics of scale the rule. Building ahead of demand actually lowered costs. The situation is now reversed. The next kilowatt is more expensive than the last and cost recovery has become contentious. Any deviation between increments of demand growth and increments of supply growth can be a source of economic and regulatory problems for the company involved.

Financial exposure when adding new capacity is now a daunting consideration. In some cases, the cost of adding a baseload generating plant can exceed the net worth of a company. Frequently construction is a threat to the financial standing of a company. Company expenditures rise, costs must be carried until the time the plant goes into service, and cost recovery with a competitive return is not assured. Financial incentives are to forego construction if at all possible. Electricity sales may be slowed by escalation in world oil prices. Changed standards for environmental controls and revised regulatory treatment pose potential financial threats against the earnings of a utility. Along with reduced sales, these factors may result in earnings levels which can not support technology commercialization. Commercialization of a new technology is limited by these financial factors and the uncertain treatment of the financial risk by public utility commissions.

Finally, the real crux of the planning problem that can cause a mismatch of supply and demand is the lead time necessary to respond to uncertain forecasts. Uncertainty is inescapable. But, the lead time problem is controllable. Many of the problems of the industry would be greatly mitigated by shortening the time from the decision to build a plant to commercial operation. Existing short lead time technologies can be selected. Today such technologies are limited to high cost oil and gas turbines. Because of the incentives not to build new plants, there is a danger that this choice will be made by default to satisfy the demands of the 1990's. New clean coal technologies may offer an opportunity for reduced construction lead time.

In summary, we are now in a slower growth, rising cost planning environment. The strategic implications of this are: (1) to build smaller scale plants relative to the past; (2) to consider renovating existing facilities; (3) to add capacity which better tracks demand growth and fluctuations; and (4) to select technologies with a higher ratio of variable to total costs.

The Technology Options

Utilities have a number of supply options with which to meet growing demand. Current technologies can meet future demand. But, current planning considerations compel a search for new options. A quick review of conventional choices illustrates the point.

Because of a decade's accumulation of regulatory, management, and public decisions, the promise of nuclear power is now eclipsed for any utility needing additional capacity before 2000. Under present regulatory and institutional arrangements, American electric utilities are not evaluating ordering nuclear plants. The cost and risks of nuclear development in the United States presently tend to price it out of the current market.

Conventional coal technology, although capable of filling the need, comes with its own set of problems. Coal plants can satisfy all existing and proposed environmental regulations; but, the cost is high. Currently, 34 percent of the physical cost of a plant is for environmental control. Also, economies of scale make an efficiently sized plant too large for the demand increments of many utility systems. Finally, the conventional method of burning pulverized coal is technologically mature. There have been no significant improvements in heat rate (coal burned per kilowatthour produced) in many years.

Other options are becoming a part of utility resource plans. Utilities are buying power from third-party producers (cogeneration and small power production). Utilities are also actively pursuing other non-conventional generating technologies such as low-head hydro, wind, geothermal, biomass, solar thermal, photovoltaics, and fuel cells. The costs and technological risks associated with these technologies place limits on their development over the next decade.

Although the focus today is on generating capacity, we should also note that utilities are pursuing demand-side management. These techniques can hopefully give us some control over the timing of capacity needs and modify demand to allow efficient use of capacity that is in place.

THE BENEFITS OF CLEAN COAL TECHNOLOGIES

There are a variety of technical benefits to clean coal technologies including modular construction, short construction lead times, environmental enhancements, wider coal selection, and improved efficiency in the conversion of raw BTU's to electricity which address the challenges described above. All of these are important national benefits also.

Environmental Benefits

Environmental quality is a public benefit that has been a goal of governing policy for years. The inherent characteristics of clean coal technologies lead us to believe that the environmental benefits will be significant. Clean Coal technologies appear to have the potential to reduce emissions levels more than existing technologies. Table 1 below indicates the emissions control potential associated with these technologies:

TABLE 1

EMISSIONS CONTROL POTENTIAL

Technology	SO_x (% removal)	NO_x ($lb/10^6$ Btu)	Particulate ($lb/10^6$ Btu)
Conv PC/FGD* 1	90-98	0.5-0.6	0.03
AFBC 2	90-95	0.2	0.01
Adv PC/FGD 3	90-95	0.2-0.3	0.01
PFBC 4	90-95	0.1	0.01
GCC 5	90-99	0.1-0.3	0.003
Fuel Cell GCC	99+	0.003	nil
Slagging Combustor 6	90-95	0.1	0.01

---

* New Source Performance Standards (values listed are legal maximum emissions--not the potential)

1 Conventional Pulverized Coal with Flue Gas Desulfurization (FGD)

2 Atmospheric Fluidized Bed Combustion

3 Advanced Pulverized Coal/FGD

4 Pressurized Fluidized Bed Combustion

5 Gasification Combined Cycle (GCC)

6 Limestone injected with Staged Combustion/Baghouse or ESP

For varying technologies, these potential benefits may be realized either on new generating capacity, or through the retrofit of existing sources to meet demands for reducing emissions from existing coal-burning power plants.

All of these potentially offer significant advances over current technologies. Of the advanced technologies, performance data are available only on the gasification combined cycle system now being demonstrated in California. After 10 months of operation, the SO_x and NO_x emissions are well within the design standards of the plant and are significantly lower than existing coal-fired plants with flue gas desulfurization systems. While this is only one plant relying primarily on one type of coal, we believe it offers significant insights into the potential of these technologies in both new and retrofit situations to utilize all qualities of coal in environmentally acceptable ways. Because several technologies appear potentially to offer similar reductions in emissions, all of these technologies need widespread demonstration to enable our industry to evaluate adequately the most cost-effective technology.

Current Flue Gas Desulfurization (FGD) technologies represent economic costs to our industry. EEI's Construction Committee has estimated that FGD adds 34 percent to the cost of new coal-fired power plants. FGD systems are complex chemical engineering facilities that are difficult to apply to existing facilities. According to EPRI calculations, maintenance costs for FGD systems are two to twenty times the maintenance costs for the rest of the power plant. Difficulties with FGD systems have reduced the availability of coal-fired power plants, thereby adding to utilities costs. Clean coal technology demonstrations, including less costly and more reliable FGD systems, offer an opportunity for utilities to evaluate the effectiveness of new technologies in meeting national environmental goals.

Technology Driving Regulation

An important element of the federal role is to assure that technology drives regulation in industries where that is appropriate. I have noted above the high cost and unreliable nature of current flue gas desulfurization systems. It would be indeed unfortunate if that system were to be the only technology choice for burning coal in an environmentally acceptable manner. We believe that the thorough demonstration of these various high-technologies offers us a potential to demonstrate the best means for environmental control based upon technology performance. Cost-based performance and selection, rather than a regulatory-imposed selection, can provide the most cost-effective benefits to the American people. Technology selection would apply to our industry's need at a plant to be retrofitted or a new one.

Modular Construction

New technologies are characterized by modular construction techniques. This results in fabrication of the system components off-site and transportation to the plant location by truck, barge, or rail. Modular construction may also result in parts of a system being brought on line at different times to meet elements of growing load demand. For example, a turbine might be brought on line fueled by oil or gas as the first element of a combined-cycle plant; later the turbine would use fuel produced by the plant after plant construction. In this way, modular construction is able to assist in meeting rapid growths in electric demand.

One particular advantage of modular construction is that rapid assembly is possible. To date, the Cool Water Gasification Combined Cycle Plant in California is the most prominent example of modular construction. Due to its modularity, it was constructed in 28.5 months from ground-breaking to the time of operation. This construction time of under 2.5 years is about one-third that of a conventional coal-fired generating station. Shorter construction times make it possible for utilities to respond more precisely to changes in demand thereby reducing construction costs as well as financial risks. In the case of Cool Water, the actual cost was $31 million below estimated costs. Modular construction would result in power stations resembling a chemical plant, and like chemical plants, they would be available in different sizes.

Wider Fuel Selection

Today utilities frequently design a boiler to burn a coal with specific qualities. The entire plant is designed around parameters of the coal such as heating value, ash, sulfur, and trace metals contents. Clean Coal technologies, particularly gasification combined cycle and fluidized bed systems, appear to offer the potential to use a broader range of coals. They would permit wider competition in the coal market to serve utilities and industrial customers. The entire coal market would potentially be increased because coal could be used where environmental standards may otherwise preclude it.

Improved Efficiency and Availability

The technology of burning pulverized coal has been in existence, essentially unchanged, for about the last 50 years. Improved thermodynamics in the conversion process of coal to electricity assist in raising generating station efficiency and lowering electricity cost. New technologies can become the basis of improved efficiences because of the various means that offer enhanced thermodynamics.

Similarly, because these plants are modular and may be built in series, repairs and maintenance of a system component may not shut the entire plant down as is likely to today. Instead, it is possible that throughputs of a production stream can be increased to compensate for a shut-down component resulting in power production remaining at the same level. This will lessen the risk that a single plant component would be able to shut down a single unit or plant. Through these techniques, the availability or time the plant is producing power can be increased which reduces the amount of capacity needed to meet electrical load. Overall, this has the potential of reducing financing costs for plants not used regularly.

Regulatory Agency Limitations

Federal Energy Regulatory Commissioner Charles G. Stalon has noted that state regulatory agencies have limited abilities to approve utility expenses that are incurred beyond the narrow definition of producing utility services. He concluded that the processes of regulatory agencies are not designed to make good decisions on research funding.

Current regulatory policies for the most part impede the recovery of costs associated with the commercialization of clean coal technologies. This requires utility companies to shoulder significant financial burdens.

The Chief Operating Officer of Virginia Power Company, Jack H. Ferguson, observed in February that, "Without Federal support we could easily have a situation in which utilities will not embrace, and their regulators will not permit, new technology until it is demonstrated by another company. Everyone could be waiting for someone else to take the hazardous trek across the desert in search of the fertile lands beyond. That policy could reflect the observation that it is often not the pioneers but the followers who gain the greatest benefits with the least cost. While this may be a prudent approach for each utility and its regulators, it will not be in the best interest of the nation."

As an incremental partner with utilities and private industry, the Federal Government can help assure that this course of action does not occur.

THE APPROPRIATE ROLE OF THE FEDERAL GOVERNMENT

Unquestionably the Federal Government should be involved in the development of clean coal technologies.

If it is in the national interest to further technologies such as clean coal combustion, then the government must consider moving down the road from generic R&D toward commercialization. Government participation can help overcome technical, financial, and institutional barriers and enrich the choices for commercialization. Federal involvement should be structured along the lines of an investment banker where funds are advanced to specific parties for demonstration of promising technologies.

There is a guarantee of a stream of information that indicates whether a certain technology is cost-competitive when applied to utility scale applications. The information stream is probably most important for our industry for future planning for the retrofit of old plants and construction of new ones.

Government support for this program should not stop at the proof of concept scale as currently advocated by the DOE, but should be carried through the stage of commercial demonstration. The Energy Research Advisory Board (ERAB) has correctly noted the difficulty in bringing many of these clean coal technologies into full-scale utility application.

CONCLUSION

Clearly the advantages of clean coal are substantial. Some of these advantages such as modular construction are reflected in the investment decision process and will be captured by electric utilities and their customers. Others, particularly the environmental benefits of SO_x, NO_x and particulate removal, reflect larger public concerns. It is the responsibility of the government to assure achievement of these benefits for both new and retrofit applications.

To do that, the government must focus on two issues. First, it must act now. The decision window for planning facilities which will be needed in the 1990's is now. Without prompt action the probability of additional conventional facilities is greater. Without prompt action the United States will be handicapped in world technology competition.

Second, the government must recognize the role it can constructively play to move technology from R&D to commercialization. The primary role is with the private sector. But, when the public benefits are large and not fully reflected in the private investment criteria, then it is the proper function of the government to take action to capture those benefits for the public good.

We appreciate the opportunity to present our views on this program of vital interest to our industry and the health and well-being of our Nation.

STATEMENT OF CHARLES S. MC NEER
CHAIRMAN OF THE BOARD & CHIEF EXECUTIVE OFFICER
WISCONSIN ELECTRIC POWER CO.
TO THE
ENERGY DEVELOPMENT AND APPLICATION SUBCOMMITTEE
OF THE HOUSE SCIENCE AND TECHNOLOGY COMMITTEE
MAY 8, 1985

Mr. Chairman and members of the subcommittee, I am Charles McNeer, chairman and chief executive officer of Wisconsin Electric Power Co., Wisconsin's largest electric utility. We supply energy services to more than two million people in a 12,000 square mile service territory in both Wisconsin and Upper Michigan. I welcome the opportunity to provide this statement in support of the Clean Coal Technology program and the system known as pressurized fluidized bed combustion.

I am sure you are all keenly aware of the important role that coal plays not only in the generation of electricity in the United States, but also in the economy of various regions of our country. Let me provide some additional perspective. The electric utility industry is and will continue to be the nation's major consumer of coal. By 1995, electric utilities are expected to account for 86 percent of total U.S. coal consumption. Coal will be used to generate 55 percent of total electricity produced in this country by 1995, up from 51 percent in 1980.

Coal from the Eastern and Midwestern United States has played a major role in meeting our energy needs. But its future and the jobs that go with it are clouded by uncertainty, as proposed restrictions on sulfur dioxide emissions could make Eastern and Midwestern coal less desirable.

At Wisconsin Electric, about 60 percent of our electricity comes from coal-fired generating plants. Fifty-three percent of the coal we use comes from Kentucky and Illinois. Ten years ago, 70 percent of our coal came from Midwest suppliers.

With electricity a major factor in economic growth, it is important that the nation's No. 1 fuel -- coal -- be given high priority when we make decisions about our economic future. Western coal will continue to be a popular product because of its low-sulfur content. However, while our country's coal reserves are enough to last 300 years, the uncertainties that surround the use of higher sulfur coal have placed those reserves in doubt. They also have forced electric utilities around the country to seek more expensive alternatives. Those alternatives include the use of low-sulfur coal or the construction of power plants with expensive pollution control systems.

The uncertainties surrounding higher sulfur coals stem mainly from the public perception that acid rain is menacing our environment. The public is asking for two things -- first, a clean environment and second, adequate and economical supplies of electricity. The two concerns need not be in conflict.

Acid rain is a phenomenon that needs to be handled in a coordinated way, on a national and international basis, with the costs shared equitably. Earlier this year, I sent letters to all members of the Wisconsin congressional delegation, noting that Wisconsin Electric can and will support appropriate national legislation to address concerns about acid rain. I have attached a copy of one of those letters to my statement here today. In it, I proposed that any national legislation be implemented in two phases. The first would set reasonable, cost-effective requirements to address emissions around the country. The second phase would take into account all of the research that is now starting to come together, along with the new clean coal technologies that are being developed.

With the expected increase in the use of coal, it is even more important that we begin today to demonstrate these technologies so that we will have options available in the 1990s. Other options, such as scrubbers or the use of low sulfur coal, are expensive, threaten the loss of thousands of jobs and represent short-sighted solutions to a long-term need.

That is why support for the Clean Coal Technologies Program is vital. That is why I ask your support for what I believe is the boiler of the future -- the pressurized fluidized bed combustion project that Wisconsin Electric has proposed to construct in cooperation with Foster-Wheeler Development Corp., Brown Boveri Corp., Gilbert/Commonwealth and Research-Cottrell.

Wisconsin Electric has a long and successful tradition of leadership in research and development programs for coal-fired power plants. Early in this century, we were the first utility in the world to burn pulverized coal for the generation of electricity, and we constructed the world's first plant built to burn pulverized coal exclusively. Our pioneering efforts in coal research led to world records in power plant efficiency.

We haven't ignored the customer side of our business. Wisconsin Electric has been a leader in successfully controlling increases in demand for electricity, and reducing the need for new power plants, through innovative conservation, rate and load management programs. One measure of our success was our ability to reduce rates three times in the past 15 months -- a record unmatched by any major U.S. utility.

Our latest project -- the pressurized fluidized bed combustion system -- will reduce sulfur dioxide emissions by up to 90 percent -- even while using Midwestern coal. The system readily meets new source performance standards for nitrogen oxide emissions, and it has the potential of operating as much as 15 percent more efficiently than today's conventional coal-fired power plants. This along with the potential for shorter construction times and lower construction costs could effectively reduce electric energy costs to our customers. This revolutionary system can mean a strong future for coal mined east of the Mississippi River. It can mean economical electricity production. And it can mean a cleaner environment.

Not only is our country involved in an acid rain debate that could limit our use of coal, we also find ourselves in an era when adding new nuclear power plants is not a practical option. Because of cost and regulatory uncertainty, the electric utility industry simply cannot plan today for additional nuclear plants. That establishes a persuasive case for the need to demonstrate practical Clean Coal Technologies.

Wisconsin Electric cannot ask its customers and stockholders to take on the sole responsibility for demonstrating the PFBC. We believe it is a project that could benefit the entire nation and as such should appropriately receive national support. Neither can we ask the federal government for total financial support. That is why Wisconsin Electric has started an ambitious national campaign to seek additional funds for this project from the coal and utility industry and others that would benefit from a demonstration of the commercial viability of the PFBC technology.

Our PFBC project is vital to the economic future of our country, and can help us maintain our energy independence. I urge your support for the clean coal technology program and for the Wisconsin Electric PFBC demonstration project I have described.

Thank you for the opportunity to provide this statement.

Wisconsin Electric POWER COMPANY
231 W MICHIGAN P O BOX 2046 MILWAUKEE WI 53201

February 19, 1985

Hon. James Sensenbrenner, Jr.
2444 Rayburn House Office Building
Washington, D.C. 20515

Dear Congressman Sensenbrenner:

The legislation proposed by the National Governor's Association offers the framework for a reasonable approach to the concerns about acid rain, but also contains provisions that would significantly increase the price of electricity in Wisconsin.

While I cannot support the NGA proposal as written, it does address some important elements that should be included in any national approach to this issue. Those elements are:

--a two-phase sulfur dioxide emissions reduction program;
--a first phase requiring reasonable reductions in sulfur dioxide emissions that can be obtained in a cost-effective manner;
--an expanded and accelerated research program;
--a second phase that would be implemented only if the research and an assessment of the first phase results demonstrate the need for more controls; and
--an implementation schedule for phase two that will allow for cost-effective advanced technologies for sulfur dioxide emissions reductions to become commercially available.

I should point out that the NGA bill is by no means the moderate bill some have suggested it is. In fact, it goes far beyond the issue of acid rain. It virtually requires a minimum 10-million-ton sulfur dioxide emissions reduction and it gives unprecedented decision-making power to the EPA administrator. These provisions make the bill unacceptable as a whole. Let me explain further.

As written, the NGA bill would likely force Wisconsin Electric to install scrubbers on one or more of our power plants in phase one. Rate increases of at least 10 percent would be necessary if these scrubbers are required.

An alternative that we favor would be first phase reductions on the order of three million tons of sulfur dioxide a year from 1980 levels, and flexibility for utilities in how they meet such reductions. This would allow us to avoid making huge financial commitments to retrofit older units with extremely expensive scrubbing equipment that may later prove unnecessary.

During phase one, we should proceed with an expanded research program that would be used along with the results on the phase one reduction program to determine whether it is necessary to proceed with additional controls. Reductions in the second phase should be tied to the demonstrated need for more controls and to the availability of cost-effective emissions reduction technologies.

The NGA bill takes the opposite approach. It says the second phase could be reduced or eliminated only if the EPA administrator convinces Congress that such a change will increase protection of resources. This is an impossible test. If the Congress is unconvinced, or if one tree or lake could be said to be potentially susceptible to damage, the additional phase two reductions must take place.

In addition, the bill authorizes the EPA administrator to further increase sulfur dioxide reductions and require nitrogen oxide emissions reductions in the second phase. He would have to explain to Congress only if he chose not to require nitrogen oxide reductions.

We believe decisions about implementation of the second phase, or about even more stringent emissions reductions, should be made by Congress, not the EPA administrator. These decisions should be based on technical, economic and public policy information. To leave such decisions in the hands of the EPA administrator, as the NGA proposes, authorizes an inappropriate exercise of the administrator's judgment and authority.

Equally troublesome is the fact that the NGA bill undermines the powers of the existing Clean Air Act, which is the vehicle already established by Congress for dealing with such issues as ambient air quality, health effects and visibility. The NGA bill's broad statement of purpose seems to empower the administrator to circumvent this vehicle and its well-established health and welfare standards.

Acid rain is a national issue, and as such should be dealt with on a national level. This bill, however, does so in an unacceptable manner. I urge you not to join as a co-sponsor of this bill until modifications are made.

Despite the national nature of the acid rain issue, Wisconsin has taken steps to reduce sulfur dioxide emissions. These actions include:

--state legislation placing a cap on utility sulfur dioxide emissions;

--new state Department of Natural Resources rules requiring further sulfur dioxide emissions reductions;

--a $1.7 million research project into the causes and effects of acid rain, conducted jointly by state agencies and utilities, with the utilities providing $1 million. This research so far shows no evidence of acid rain damage to lakes or forests in Wisconsin.

On its own, Wisconsin Electric recently has embarked on a revolutionary new sulfur dioxide emissions control project. We have indicated our desire to be the host site for a pressurized fluidized bed combustion (PFBC) demonstration unit at our Port Washington Power Plant. This unit could remove some 90 percent of the sulfur from the coal as it is burned, and could yield important data that would help bring such PFBC units to commerical availability.

I am concerned that in the absence of preemptive federal action, Wisconsin and other states will take further uncoordinated steps to independently reduce sulfur dioxide emissions. This would be counterproductive on two fronts. If Wisconsin acts alone in reducing sulfur dioxide emissions, those reductions would be so insignificant on a national basis that they would have no measurable effect, positive or negative, on the environment. And, by standing alone to require emissions reductions, Wisconsin would put its businesses and its citizens at an economic disadvantage. Acid rain is a phenomenon that needs to be handled in a coordinated way, on a national basis and with the costs shared evenly.

Finally, while I don't mean to suggest that acid rain will just go away, there are several developments on the horizon that will help mitigate its effects. For instance, as older plants are retired, newer plants burning lower-sulfur coal will come on line. New sulfur and nitrogen oxide emission reduction technologies that can be retrofitted onto older units may soon become commercially viable. Given time, these two factors alone could make a big difference in the scope of the problem. This, combined with the expanded research program proposed by the NGA should make it easier for us to determine whether additional control measures are necessary.

This NGA bill also contains numerous other provisions that are objectionable and that I would be pleased to discuss with you in more detail. Do not hesitate to call.

Sincerely,

Charles McNeer

Charles S. McNeer
Chairman of the Board and
Chief Executive Officer

cc: Governor Anthony Earl
Secretary Carroll Besadny
Chairman Ness Flores
Commissioner Branko Terzic
Commissioner Mary Lou Munts

APPENDIX II

Department of Energy
Washington, DC 20585

June 14, 1985

Honorable Don Fuqua
Chairman, Committee on Science
and Technology
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

On May 8, 1985, Assistant Secretary William Vaughan appeared before the Science and Technology Subcommittee on Energy Development and Applications concerning the clean coal technologies initiatives.

Following that hearing, you submitted written questions for our response to supplement the record. Enclosed for your information are the answers to those questions, which also have been sent directly to the Committee staff.

If you have any questions, please call Ingrid Nelson or Cathy Hamilton of my staff on 252-4277. They will be happy to assist you.

Sincerely,

Cathy J. Hamilton
for Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosures

EMERGING CLEAN COAL TECHNOLOGIES

Question #1: There has been mention of using the National Coal Council in the Emerging Clean Coal Technologies Initiative. Please expand on this possibility. Please characterize that group as to occupations, coal industry experience, availability, and geographical representation.

Answer: The Charter of the National Coal Council states, in part, that the National Coal Council can provide advice and recommendations on such matters as "scientific and engineering aspects of coal technologies, including emerging coal conversion, utilization, or environment control concepts." Therefore, it would not be inappropriate for the Council to be asked by the Department (Secretary) to provide recommendations involving emerging clean coal technologies.

The Council is in the very early stages of organization, with the first meeting scheduled for June 10. Clearly, the initial emphasis will be on developing a workable organizational framework that will permit the Council to function effectively in its advisory capacity. Once the Council is in a position to accept assignments from the Secretary, emerging clean coal technology could be a study topic.

The Coal Council was established with the objective of bringing together a wide diversity of professional backgrounds and geographic representation. Twenty individual categories of coal-related expertise are represented on the Council with members from producers, shippers, transporters, equipment manufacturers, industrial and utility consumers, research organizations, environmental groups, union and non-union labor, tribal councils, and related fields.

Representatives were also selected with the objective of providing as broad a geographic representation as possible. Accordingly, members are included from more than 30 states.

A specific attempt was made to include senior level representatives of corporations and institutions. Typically representation is at the Chief Executive Officer, President, or Board Chairman level, as appropriate. Many of these individuals have more than four decades of personal experience in coal mining and related industries. One of the principal attributes of the Coal Council is that it makes available to the Executive Branch an exceptionally high degree of industry experience.

Regarding the availability of Council members, the charter requires that all members convene twice each year in a meeting of the entire Council. Members, of course, can and will meet more frequently as specific projects are undertaken.

EMERGING CLEAN COAL TECHNOLOGIES

Question #2: In DOE's Emerging Clean Coal Technologies Report's assessment of alternative fuels, the potential for significant oil displacement by coal water mixtures is examined. The Report anticipates that the highest displacement will occur at the higher-risk end of the technology spectrum, including heat engine applications. The assessment concludes that this area "is prime for Federal stimuli and one for which DOE's program is focused.

Please address how DOE is and intends to focus on stimulating research and development of the application of coal water slurries to heat engines.

Answer: Under its Heat Engines Program, DOE is procuring experimental quantities of advanced coal water slurries and highly-beneficiated dry coal for evaluation in engineering tests under simulated heat engine operating conditions. The objective of these tests is to provide the data to solve major engineering, design, durability, and performance problems associated with the substitution of coal or coal-derived fuels for distillate fuels and natural gas in firing gas turbines and diesel power conversion systems. In this way, DOE is evaluating advanced fuel forms with the view toward heat engine application.

EMERGING CLEAN COAL TECHNOLOGIES

Question #3: Please respond to the statement in ERAB's report that, "Acceptance of coal water slurry by the utility will require further extended large scale combustion tests. The private sector seems to be ready to pursue this subject; however, the high cost of large-scale tests will require substantial DOE assistance."

Answer: The DOE has sponsored extensive combustion tests to establish the feasibility of using coal water slurries in oil designed utility boilers. We would agree with ERAB that, partly because of the results of these tests and other privately sponsored tests, "the private sector seems ready to pursue this subject." However, we do not agree that "substantial DOE assistance" is appropriate or required. Sufficient progress has already been made in the development of coal water slurries for large utility boiler applications to make this fuel ready for private sector commercialization.

For example, Babcock & Wilcox and Combustion Engineering are developing utility-size coal-water slurry burners. The Electric Power Research Institute is conducting a comparative evaluation of utility-sized burners using coal-water fuels from several manufacturers. Boston Edison recently tested coal-water slurry in two burners of a 125-megawatt boiler. Coal-water fuels produced by the Cape Bretton Development Company's Nova Scotia plant are being burned in a small, coal-capable utility boiler at New Brunswick Electric Power Company's Chatham Power Station in an extended demonstration. Also, Nycol of Sweden is supplying commercial quantities of coal-water fuel to the Sundbyburg power station in suburban Stockholm.

In view of this, we believe the proper DOE role should now be focused on the higher risk small industrial, residential, and commercial markets which have significant potential for oil and gas displacement.

EMERGING CLEAN COAL TECHNOLOGIES

Question #4: ERAB's report recommends that DOE increase its efforts to co-fund programs aimed at waste utilization rather than disposal. How does DOE plan to respond to this recommendation?

Answer: The Waste Management Program is not supporting work in the waste utilization area as a matter of DOE/FE policy. This policy is based on a number of considerations. First, extensive R&D has been conducted in the area of coal waste (mostly ash in some form) utilization over the past several decades. This technology is largely mature and in general has not been very cost effective. Second, research in waste utilization has been an open-ended R&D area which has seldom resulted in new products. Third, even the more successful coal utilization schemes have done little to mitigate the waste disposal problem.

In the effort to assist the private sector for greater utilization of coal use waste products without developing new methods, the Department of Energy will support a project to develop and publish a textbook dealing with engineering design practice for high volume coal combustion ash by-product and flue gas scrubber waste utilization technology.

To complement the waste utilization work that was done in the past and is now being conducted by the private sector, DOE has focused its efforts on the characterization and assessing the leachage and behavior of the wastes from the advanced technologies being developed in the fossil energy program. In addition, DOE is researching methods of energy recovery from coal preparation wastes.

EMERGING CLEAN COAL TECHNOLOGIES

Question #5: Would it be within the Administration's definition of the "proper" federal R&D role for DOE to fund a test program in which the various coal locomotive concepts are demonstrated and compared in conjunction with the private sector to allow the private sector to pick the concepts most commercially feasible? Please respond to the points discussed in the following background.

Background Such a program would fulfill Congressional and other requests for federal financial support of a coal locomotive prototype while minimizing the federal role in choosing between technologies. Such a program could be operated on a cost-shared basis with the combustion system manufacturers as well as with other interested private sector parties. Concepts suitable for such a program include, but are not limited to: AFB, coal-water mixture, pulverized coal, producer gas, coal-fired diesels and coal-gas turbines.

Answer: In the Administration's view, the federal government should not fund a test program in which the currently proposed coal-fired locomotive concepts would be demonstrated under conditions that would permit the private sector to compare their commercial feasibility for the following reasons. Nine different concepts were proposed ranging widely in development requirements, costs, schedules, risks, and potential pay-back. To ensure an equitable basis for comparison, such a program could cost upwards to a billion dollars and take 6 to 10 years. A crash program of this kind is not justified by technical considerations. Some of the concepts presented represent merely evolutionary improvements over the last generation of post World War II steam locomotives. Others, like the coal-fired diesel or gas turbine, are revolutionary in nature. Still others apply relatively well established coal utilization technologies to steam reciprocating engines. In our view, it is clearly not a proper government role to indiscriminately fund demonstration programs of such disparate concepts in order to facilitate commercial assessment.

Rather, the proper federal R&D role in this technology area is to conduct long-range, high-risk research to determine if it is feasible to use coal in diesel engines to provide power to stationary sources or the transportation sector. This effort is currently being conducted under the Fossil Energy R&D Heat Engines program. A copy of a recent DOE news release related to this area is attached.

U.S. DEPARTMENT OF ENERGY
OFFICE OF THE PRESS SECRETARY
WASHINGTON, DC 20585

DOE NEWS:

NEWS MEDIA CONTACTS:
Robert C. Porter (Washington) 202/252-6503
Claire H. Sink (Morgantown) 304/291-4620

FOR IMMEDIATE RELEASE
May 14, 1985

ENERGY DEPARTMENT AWARDS CONTRACTS TO RETURN COAL TO DIESELS

Three research teams, each including a major U.S. diesel manufacturer, have been awarded government contracts to determine if it is feasible to use coal in diesel engines to provide power to stationary sources and to run locomotives and small ships, Secretary of Energy John S. Herrington announced today.

The contracts were awarded by the U.S. Department of Energy's Morgantown (WV) Energy Technology Center. Their total value exceeds $5 million and includes more than $725,000 of private sector cost-sharing.

"The results of these three contracts will help provide the groundwork for industry to decide if U.S. manufactured diesel engines can be fueled with coal, which is our most abundant domestic resource," Herrington said. "A positive result could assist us in our long-term goal of reducing the country's need for foreign oil."

One team, made up of Arthur D. Little, Inc., of Cambridge, Mass.; Cooper-Bessemer Diesel, of Grove City, Penn.; and the Massachusetts Institute of Technology, Boston, will study large, coal-fired, stationary industrial cogeneration and maritime diesel applications. It will receive $1,330,000 in federal funds and will contribute another $98,000 of private funding.

R-85-045

A second team, involving the Locomotive Division (Erie, Penn.) and the Corporate Research and Development Center of the General Electric Co. (Schenectady, New York) will investigate locomotive applications for coal-burning diesels. Federal funding for this effort will total $1,730,000 with another $297,000 to be provided by the private participants.

The third team includes the Allison Gas Turbine Division (Indianapolis, Ind.) and the Electro-Motive Drive Division (LaGrange, Ill.), both part of General Motors, and the Southwest Research Institute of San Antonio, Tex. It will also study locomotive applications using $1,290,000 of federal funds and $320,000 of private funds.

Each contract will run for two years.

The Energy Department's objective is to develop ways of reintroducing coal into an engine that once was intended to burn coal but now is fueled solely by oil.

When Rudolf Diesel conceived the diesel engine in the 1890s, he envisioned it as a way to produce power by burning both solid and liquid fuels. Research in the 1920s through the early 1940s, principally in Germany, dealt with the burning of solid fuels in low-speed diesels commonly used in Europe. After World War II, inexpensive and abundant petroleum pushed the abrasive, solid coal fuels out of the diesel market.

The oil shocks of the 1970s revived interest in the coal-fueled diesel.

Exploratory tests in the early 1980s and further development in related areas such as cleaning coal of ash and sulfur, and grinding and slurrying very fine coal have increased the Energy Department's confidence that coal could still become a candidate fuel for U.S. manufactured diesels.

The U.S. effort to be undertaken by the three firms will focus on the medium-speed diesel engine, the major source of power for domestic locomotive and inland waterway transportation. Such diesels are also used in small utility and industrial applications. Together, these applications today consume more than 1.8 million barrels of oil daily.

-DOE-

R-85-045

EMERGING CLEAN COAL TECHNOLOGIES

Question #6: What is DOE's opinion on the comparative applicability of these concepts to locomotive use?

Answer: In the DOE's opinion, the coal-fired diesel-electric locomotive is probably the most currently useful concept because it would retain the flexibility and efficiency of the basic diesel cycle while conserving a major part of the current capital inventory. The coal-fired gas turbine-electric traction drive is less attractive from the standpoint of flexibility but may have an advantage over the diesel as it could prove to be more tolerant to ash forming impurities in the coal fuel. Both major U.S. locomotive manufacturers are comparing the two concepts in engineering studies and experimental work under DOE contract. In addition, locomotive manufacturers and railroad operators are cooperatively studying both systems - as well as others - analytically and experimentally. The remaining concepts rely principally on steam cycles - turbines or reciprocating engines - and, while there is little doubt concerning their ultimate technical feasibility, there is considerable uncertainty about their applicability and ultimate economic benefit to the transportation industry.

EMERGING CLEAN COAL TECHNOLOGIES

Question #7: What are your views on the technical and international merits of the joint U.S. - China development of a new coal-fired steam locomotive? Please respond to the points discussed in the following background.

Background This concept is based on the competitive evaluation of applicable clean-combustion technologies in an existing Chinese production steam locomotive. Such a concept appears to have three significant advantages. First, it will introduce a commercially feasible, environmentally acceptable new coal-based locomotive to American railroads in the shortest possible time. Secondly, it is not locked into a specific coal combustion technology, but will promote joint coal-combustion technology development between the United States and China.

Answer: The Department of Energy agrees that the development of this concept would provide a basis for comparing various coal processing and combustion technologies in locomotive duty cycle service. The resulting product would indeed represent a class of "new coal-based locomotives" which could probably be built and run in "the shortest possible time." The concept is similar, in principal, to other proposed concepts that apply new coal processing and combustion technologies to steam reciprocating engine drives. The locomotives would not, however, preserve the efficiency and flexibility advantages of modern diesel powered locomotives. Their ultimate pay-back to the railroads would be limited, we believe, by this fact. As to the suggestion that this concept's inclusion of various technologies would avoid its being "locked-in" to one in particular, we see little merit in this. If serious consideration were given to a limited-objective coal-fired steam locomotive, it would clearly be in order to first critically study the options and then select the preferred one, with a possible back-up, for engineering evaluation. Furthermore, we believe there are more suitable mechanisms for the conduct of joint coal technology work with foreign nations than through a market-oriented program such as that proposed here.

This is particularly true when the markets and existing capital equipment base are as different as they are between the U.S. and China.

QUESTIONS SUBMITTED BY CONGRESSMAN RICK BOUCHER

Question #1A: The appropriateness of clean coal technologies vary widely according to numerous factors including characteristics of the fuel, the age and size of the facility, and the emission reduction goal. Therefore, no one proposal could be expected to present the single technology for all purposes.

Would it be the intention of DOE to develop as wide a range of technologies as possible?

Answer #1A: Yes, the appropriateness of different clean coal technologies varies according to several factors and no one technology or subsystem can be expected to solve all of the problems involved in expanded coal utilization.

Question #1B: Would an integrative approach be taken whereby those technologies would be developed that could be joined together in different ways, for example coal cleaning with limestone injection multi-stage burners (LIMB), to achieve overall emission reduction targets?

Specifically, what are the kinds of technologies with the greatest potential for integration with other kinds of technologies and for what kinds of applications?

Answer #1B: The DOE coal research program is intended to result in the introduction of total systems (from coal mine to end user) which will allow for cost-competitive and environmentally acceptable utilization of coal not only in the existing and future utility market but the industrial, residential/commercial and transportation sectors as well. We make every effort to consider each of the technologies within the context of how they will fit into an integrated system. The example cited by Congressman Boucher is but one of many ways in which subsystems can be integrated to form a total coal-based system. We have not done an analysis to determine which technologies have greater potential for integration. However, a few general observations can be made:

- All of the coal technologies being pursued by DOE have the potential for integration into total systems. Some are more amenable to limited applications while others, if developed to the point of being cost-competitive, could be a part of coal-based systems serving all of the consuming sectors.
- Coal cleaning and gas cleanup should be considered as potentially a part of most coal-based systems.
- Technologies are commercially available for using coal in the utility sector, but with just a few exceptions, environmentally acceptable and cost-competitive coal-based systems are not available for the other consuming sectors.

QUESTIONS SUBMITTED BY CONGRESSMAN RICK BOUCHER

Question #2: The new report by DOE on the reserve states that DOE's previous experience with federal incentives have "with few, if any exceptions been unsuccessful in commercializing new fossil technologies." Federal support for energy technologies, however, have been apparently successful in a number of areas. Atmospheric fluidized bed technologies are now being commercialized. U.S. research and development on heat pumps and photovoltaics has been adapted and commercialized by the Japanese. Wall-fired LIMB technology has been successfully demonstrated by EPA with potential application to 40% of the utility market.

What has been the role of the federal government or other governments in the development and commercialization of these technologies?

Are there other examples of successful government demonstration and commercialization of energy technologies in this country or by other countries using either their own research and development or R&D results obtained by U.S. efforts?

Answer: In general, most Government-sponsored, large-scale development work on energy technologies have resulted in one of three outcomes:

1. The large-scale unit did not realize its technical objectives, with the resulting loss of private sector interest.
2. By the time large-scale testing was completed, the clearer picture of technology costs coupled with perceptions of the future cost of competing options created an unfavorable outlook for commercial application.
3. Large-scale testing created some commercial interest, but so far application has been limited to special situations, which in some cases are dependent on Federal tax subsidies.

There have been some isolated cases where the Government has sponsored large-scale testing on technologies that have ultimately gained market acceptance. The DOE-sponsored atmospheric fluidized bed combustor demonstrations are an example, even though it is difficult to say how much these tests may have accelerated the commercial deployment that is occuring today. Photovoltaics is an example of a technology that has filled some specialized niches thus far, although it is unclear when large-scale deployment may occur. The LIMB technology has technical promise as well as considerable uncertainty as to its attractiveness with a variety of coals and boilers, but cannot really be considered "commercial" yet.

Thus, the lesson from past experience seems to be that, while it is possible that there are cases where Government-assistance could help to accelerate commercialization, the track record has not been good and there is no reason to believe that it would be any better in the future.

QUESTIONS SUBMITTED BY CONGRESSMAN RICK BOUCHER

Question #3: Report language relating to the reserve clearly states that the purpose of clean coal technologies is "for using coal in electric utility and large industrial applications that reduce sulfur and other emissions resulting from such uses to levels that are required, or may be required, for compliance with the Clean Air Act, as amended (P.L. 98-473, Senate Energy and Natural Resources report 98-578)."

Question #3A: Given the limited amount of funds available for coal research and development and the desire to develop the widest range of clean coal technologies possible, would DOE try to emphasize proposals with the greatest potential yield in terms of market application and emission reductions?

Answer #3A: If funds were appropriated by Congress for this program, the Department of Energy would recommend a course that would result in eligibility of the broadest range of technologies and market applications. As discussed in Appendix C of DOE's "Report to Congress on Emerging Clean Coal Technologies," each technology has unique advantages and disadvantages as compared with others and therefore should be given the opportunity to compete on its merits.

We would expect that under a competitive solicitation there would be significant proposals from the electric utility and large industrial sectors. However, any future program should not be limited to electric utility and large industrial boiler applications where coal will be the fuel of choice under most future energy scenarios. The principal U.S. markets for oil and natural gas are and will continue to be in the light industrial, commercial, residential and transportation sectors. Therefore, interesting projects which have the potential to move coal into these markets should not be precluded.

Question #3B: Specifically, what technologies, if successfully demonstrated, would have the quickest market applications?

Answer #3B: This question is very difficult if not impossible to answer at this time. Factors like energy prices, economic conditions, the financial health of the utility and other industries, future environmental requirements, etc. will affect market decisions to use new technologies. Because we have little to no control over these factors, the DOE's posture has been to develop data on a suite of technologies from which the private sector can choose to suit their particular needs.

Question #3C: How long would market commercialization take for these technologies?

Answer #3C: Again, market conditions, influenced by a number of potentially applicable future circumstances such as comparative fuel prices and strength or leniency of pollution emission regulations, will determine how long it will take for the successfully demonstrated technologies to be commercialized. However, it is expected that the more the private sector cost-shares in a demonstration project, the more likely they will aggressively market the technology demonstrated.

Question #3D: Specifically, what technologies if successfully demonstrated, would have the widest market applications?

Answer #3D: The information on the market applications for the emerging coal technologies being researched by DOE is attached.

Question #3E: To what extent could these technologies be expected to penetrate those markets?

Answer #3E: Although certain potential markets may be preliminarily identified, as DOE has done in the Technology Assessment section of its report, there is no way of knowing the extent to which the emerging coal technologies will penetrate the user markets. Prevailing market conditions in the future will, rather, dictate the extent of such penetration.

Question #3F: Under these assumptions, what would be the overall emission reduction potential by kind of pollutant and economic activity of commercializing clean coal technologies?

Answer #3F: Advanced clean coal technologies have the potential to reduce emissions of several pollutants normally emitted to some degree from coal including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, and trace metals. Of these pollutants, SO_2 and NO_x have received the greatest interest and quantification. Additionally, some advanced technologies are apt to be used in applications where coal is already used, such as electrical generation, and yield benefits of lower cost and reduced emissions. Other potential applications, such as in light industry or transportation, will allow less expensive coal to be used in lieu of petroleum products or natural gas, but in these cases, emissions are not likely to be significantly lower than with current fuels. Since the penetration of advanced technologies is so difficult to anticipate in terms of specific technologies, pollution reductions stated in absolute terms would be extremely speculative. The table below offers relative pollution reduction potential for SO_2 and NO_x, where it can be reasonably estimated, for various categories of technology where advanced coal technology would replace conventional coal use.

Technology	Potential Reduction (%)	
	SO2	NOx
Dry discharge FGD (e.g., CuO, E-beam, NO$_x$SO)	90	90
Limestone Injection with Multistage Burners (LIMB)	50	70
Atmospheric Fluidized Bed Combustion (AFBC)	90	70
Pressurized Fluidized Bed Combustion (PFBC)	98	unknown
Advanced Combustors (slagging combustors)	60	50
Advanced Physical Coal Preparation	65	0
Advanced Chemical Coal Preparation	99	0
Integrated Gasification, Combined Cycle Power	99	85

Emission reductions would come primarily from economic sectors currently using conventional coal combustion technology. These sectors include electric utilities and large industrial boiler users, the latter dominated by the chemical, petroleum, primary metals, stone/clay/glass, paper, and food industries.

Question #3G: Also under these assumptions, what technologies could, alone or in conjunction with other technologies, achieve the quickest reductions in emissions?

Answer #3G: In practical terms, advanced coal technologies offer the quickest reductions in emissions if they are capable of retrofit to existing coal combustion processes. In the U.S., approximately 64% of man-made SO_2, and 28% of man-made NO_x emissions are from coal-fired powerplants. Industrial coal combustion accounts for another 7% and 2% of these pollutants, respectively. Of the technologies identifed above, advanced coal preparation probably offers the fastest reductions in emissions because of the stage of development of the technology, and the comparatively short lead time required to construct preparation facilities. Other near-term technologies which could be retrofitted include dry discharge FGD, LIMB, and AFBC.

Question #3H: How long would it take to achieve the overall emission reduction potential of commercializing clean coal technologies?

Answer #3H: Retrofit of existing stationary source emitters of SO_2 and NO_x would likely require 5 to 10 years after demonstration of the requisite technologies, if a program is designed to achieve major reductions (over 50%) in emissions. However, the ultimate potential emission reductions of advanced coal technologies will not be realized until existing equipment is retired and/or replaced by new equipment incorporating advanced technology designs, like IGCC or PFBC. This ultimate achievement will not take place before the year 2040, an estimate based upon the anticipated remaining useful lives of equipment now in operation, unless currently operational equipment is forced to retire early.

Attachment

EMERGING COAL TECHNOLOGY
MARKET APPLICATIONS

Flue Gas Cleanup Technologies

The potential markets for these technologies will be primarily large industrial and utility coal-fired boilers for both new and retrofit applications. Some of the technologies, like the E-beams being developed by DOE, are being designed for new utility boilers to meet the Federal New Source Performance Standards more economically than conventional SO_2 scrubbers. The LIMB technology, on the other hand, may be better suited as a retrofit technology in the event acid rain controls beyond currently existing SO_2/NO_x emission restrictions are imposed in the future.

Advanced Combustors

The potential markets are expected to be for large industrial and utility boilers in new coal-fired applications and as a retrofit coal-based systems for large boilers now using oil or natural gas. DOE´s research program is also addressing the use of advanced combustors for light industrial, commercial and residential applications.

Fluidized Bed Combustors (FBC)

Both Atmospheric and Pressurized FBC are suited for new coal-fired utility applications as well as for the repowering of oil and gas-fired utility boilers. AFBC is being used commercially in the large industrial boiler market at this time. In addition, research is being conducted to develop

AFBC´s for light industrial, commercial and possibly residential applications. PFB may also be desirable as a pollution control, capacity boosting, technology for existing coal-fired powerplants.

Coal Preparation Technologies

Coal preparation technologies have potential application in all markets where coal is used. In addition, prepared coal, either slurried with water or dry, can provide the feedstock for a number of the advanced coal technologies presently under development as well as a coal-based fuel substitute for oil.

Alternative Fuel

Coal water mixtures have the potential to be used in a wide variety of markets where coal, oil and possibly natural gas now dominate. These include the electric utility, industrial, commercial, residential and heat engines markets.

Gas Stream Cleanup Technologies

These technologies are being developed to enable the cleaning of hot gases from some of the emerging coal technologies to improve their economic and environmental performance. Such technologies will be used with surface coal gasification, fuel cells using coal, pressurized fluidized bed combustors and direct fired turbines.

Coal Gasification Technologies

Coal gasification technologies are being used and will potentially be used for a wide variety of market applications, including in the production of industrial fuel gas (low and medium Btu gas), as a component of combined cycle units for utility applications, in the production of feedstock used in turn to produce chemical feedstocks and methanol, and, in the production of high Btu gas for direct substitution for natural gas in applications ranging from utility fuel to residential uses.

Fuel Cell Technologies

Fuel cell powerplants are expected to see their earliest applications using natural gas or distillate fuels in electric utility power generation and primarily for peaking power. Later, fuel cell plants operating on coal could expand the potential market to base load power generation and, even later, into the industrial sectors.

Fuel cells may also be utilized in the residential and commercial sectors, very likely using natural gas as the fuel.

Heat Engines Technologies

Gas turbine technologies are currently used by utilities and industry for new peak power generation, combined cycle, and cogeneration applications. The new coal-fired gas turbine technologies under development by DOE are aimed at the same markets with the potential for expansion into intermediate and possibly baseload power generation markets.

Coal-fired diesels can potentially be used in large systems currently using diesel fuel such as electric utilities, basic industries, railroads and inland waterways and marine shipping interests.

Magnetohydrodynamics

The MHD technology is targeted primarily at the baseload electric utility market.

Coal Liquefaction

Coal liquefaction technologies can produce both clean solid and liquid fuels from coal. As a result, coal derived liquids can be used as substitutes for petroleum products in almost all of its applications.

QUESTIONS SUBMITTED BY CONGRESSMAN RICK BOUCHER

Question #4: The report of the Energy Research Advisory Board supports demonstration projects for clean coal technologies for electric utility retrofit applications.

Specifically, what would be the emission reduction potential of retrofitting electric utilities with clean coal technologies in terms of extent and timing of reductions?

Answer: It would be extremely cost-ineffective to retrofit all existing emitters of SO_2 and NO_x. This fact has been recognized by the various legislative proposals to control acid rain precursors and has resulted in different approaches to additional controls on those sources that are or will be least expensive to control. If one such approach were selected and one assumed all existing powerplants with SO_2 emissions exceeding rates allowed by New Source Performance Standards (1.2 #SO_2/mmBtu) were retrofitted with an advanced technology capable of removing 90% of SO_2 and NO_x, then 1980 emission levels could be reduced by 13 million tons per year of SO_2 and 3 million tons per year of NO_x. Such technologies are expected to be mature by the early 1990's, which means they could be used in large numbers by the late 1990's. Less ambitious reduction programs could be achieved sooner using advanced coal preparation technologies.

QUESTIONS SUBMITTED BY CONGRESSMAN RICK BOUCHER

Question #5: Projections by the Energy Information Administration indicate that industrial use of coal, especially by industries with large, continuously operating boilers, is expected to increase substantially in the future. A recent report by the Office of Technology Assessment predicts that industrial emissions will be a significant portion of the total growth in emissions in the coming years.

Question #5A: Specifically, which industries have the particular need to develop clean coal technologies for expanded coal use or for compliance with Clean Air Act regulations?

Answer #5A: Compliance with current Clean Air Act requirements is generally not a driving force for the use of advanced coal technologies. Only the State of California, with its unusual air quality problems, has regulations so stringent that conventional coal technologies cannot be used. Given today's general regulatory environment, then, the need for advanced coal technologies is derived primarily from the need for expanded use of coal to replace oil and natural gas as fuels, anticipated over the next few decades. Since coal is less than one-half the price of oil or gas (per Btu), the current expanded coal use capitalizes on an economic market advantage of U.S.-based industry. Most industries which use large amounts of energy can benefit, economically as well as environmentally from clean coal technologies.

Question #5B: What kinds of technologies are most appropriate for industrial applications?

Answer #5B: Atmospheric Fluidized Bed Combustion technology is already considered commercial for industrial sized units. Other attractive technologies include advanced combustors, which may allow burning of coal in boilers designed for oil, advanced coal preparation, coal-fired turbines and diesels, coal gasification (with and without hot gas cleanup), and coal/liquid mixture fuels. The technologies that allow direct reduction of iron by coal (without the use of coke) could possibly lend a competitive edge to U.S. manufacturers, since the direct process uses a much less expensive grade of coal. In the final analysis, however, the market will strike an appropriate balance between advanced and conventional technologies and other alternatives such as conservation.

Question #5C: How could new EPA regulations concerning "tall stacks" affect this need?

Answer #5C: DOE has not evaluated the effect on the industrial sector of EPA's proposed regulation of tall stacks. EPA's published impact analysis for the proposed regulations is only three paragraphs long and considers only powerplants. It is reasonable to assume that the proposal, if implemented, would require additional reductions of SO_2 from industrial sources. Depending on the schedule of new requirements, advanced coal technologies might facilitate compliance.

Question #5D: What industrial efforts are currently underway to meet these needs?

Answer #5D: There are substantial industrial technology development activities sponsored by industry or by equipment vendors now under way. Coal technologies involved in such private sector research include advanced combustors, advanced coal preparation, coal/liquid mixtures, and direct iron reduction.

QUESTIONS FOR SECRETARY VAUGHAN

Question #1: In your testimony, you indicate that several of the emerging technological options addressed in the submissions are currently being developed at near-commercial or commercial-scale without federal money. I would like to know which of these technologies are at this stage of development.

Answer: A large number of emerging coal technologies are at the point of demonstration and/or commercial operations. Summary information on those activities categorized by technology is provided below.

Emerging Coal Technologies
Commercial Activities

Flue Gas Cleanup

(1) Aqueous carbonate-regenerable flue gas desulfurization unit. A 100 MW demonstration at Niagara-Mohawk, New York, was down early in 1985 because of problems. Rockwell International was the process developer. Sponsors were ESEERCO (Empire State Electrical Research Co.), NY ERDA, EPA and DOE.

(2) Limestone Injection Multistage Burner Projects

- A 300 MW lignite fired boiler was retrofitted and tested in Canada.
- Currently, 6 boilers, ranging in size from 20 to 330 MW, are operational in Austria, using Austrian brown coals.
- Two boilers totaling 100 MW are undergoing shakedown tests in Germany. Plans are to retrofit an additional 16 boilers, totaling 2,600 MW with LIMB systems within the next two years.
- In France, sorbent injection tests were performed on a 50 MW boiler using a variety of sorbents.

Coal Preparation

(1) Electrostatic separation. A 10 ton per hour unit is being tested at American Electric Power Picway Station in Columbus, Ohio.

(2) True heavy liquid cyclones. A several tons of coal per day demonstration unit is planned by American Electric Power Company.

Atmospheric Fluidized Bed Combustion

(1) Utility Applications

- A 160 MWe "grass roots" power plant located in Paducah, Kentucky, is scheduled for operation in the late 1980's. TVA, Duke Power, EPRI and the State of Kentucky are among the projects' sponsors.

- A 125 MWe retrofit to a Northern States Power Company plant is under construction in Burnsville, Minnesota by Northern States Power. Operation is scheduled for mid-1986.

- A 100 MWe "grass roots" circulating bed, scheduled for operation in late 1987 is planned by Colorado.

(2) Industrial Applications

Eighteen U.S. boiler manufacturers are offering commercial units for industrial boiler applications. A partial listing of the more than 100 commercial industrial AFB's located in the U.S. is provided in Attachment 1 (taken from Power Magazine - February 1985).

Pressurized Fluidized Bed Combustion

(1) The City of Stockholm, Sweden is proceeding with the retrofit of a cogeneration plant in Stockholm which will produce 235 MW heat and generate 133 MW electricity, using 2 coal-fired PFBC modules. The PFB modules will be supplied by ASEA-PFB, Sweden (formally Stal-Laval), and will be commissioned in 1989.

(2) Demonstrations under consideration include:

- Deutche Babcock

  Designing a 335 MW PFB combined cycle power plant for proposed demonstration in Germany in the early 1990s. The output from the proposed utility demonstration plant would consist of 75 MW from the gas turbine and 260 MW from the steam turbine.

- Florida Power and Light Company teamed with Babcock and Wilcox and the General Electric Company are investigating the feasibility of demonstrating a 80-100 MWe turbocharged PFB module at Florida Power and Light's Palatka, Florida, station.

- The American Electric Power Company, Stal-Laval and Deutche Babcock are investigating the feasibility of demonstrating a 70 MW combined cycle demonstration plant at AEP's Tidd Station near Brillant, Ohio.

Advanced Combustors

(1) TRW is planning to demonstrate a 50 million Btu/hr slagging combustor system in their Cleveland Airport Components Group Plant in a coal designed boiler.

(2) Rocketdyne is working with a group of utilities in an effort to demonstrate their combustor.

Alternative Fuels

Considerable private sector activity both domestically and internationally is underway in the marketing of coal-water mixtures. Attachment 2 provides summary information on many of those activities.

Surface Coal Gasification

A considerable amount of commercial activity in demonstrating gasification processes and utilizing them in commercial applications has occurred. Attachment 3 provides summary information on many of those activities.

Phosphoric Acid Fuel Cells

(1) Two 4.8 MW electric utility preprototype power plants. A project initiated in 1976, sponsored by UTC, DOE, EPRI and a utility consortium led by Consolidated Edison resulted in th installation and checkout of a 4.8 MW (4.5 MW AC) phosphoric acid fuel cell power plant in New York City. The plant was inactivated without operating due to damage to the cell stacks during storage.

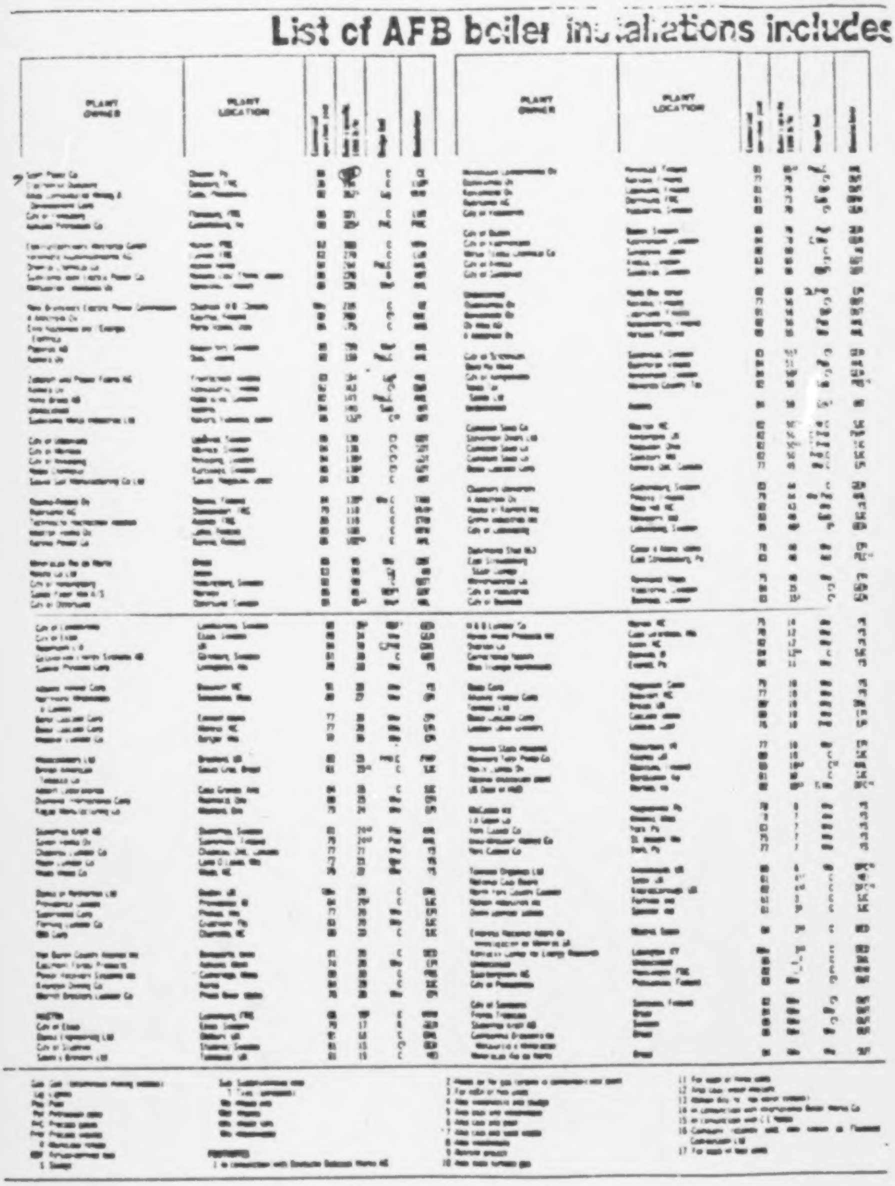
A second similar 4.8 MW power plant was purchased from UTC by the Tokyo Electric Power Company and has been installed and is operating in Goi, Japan.

(2) Field Test of 40 kW power plants. A field test of 43 40 kW UTC power plants was initiated by DOE and GRI with 36 companies participating by hosting test sites. The units produce coproduct heat for use at the test site in addition to 40 kW of electricity. Over 120,000 hours of operation have been achieved to date. Thirty-five power plants are installed and the final plants are expected to begin operation in June 1985. A list of the sites is provided in Attachment 4.

(3) Formation of International Fuel Cells Corporation. On April 8, 1985, International Fuel Cells Corporation was formed to develop, manufacture and sell fuel cells worldwide. The Corporation is a U.S. company in which United Technologies Corporation and Toshiba Corporation each own 50 percent of the corporate stock. Commercial orders for power plants are expected in 1985 with earliest deliveries in 1989.

Power Magazine Feb. 1985

Attachment 1



List of AFB boiler installations includes

PLANT OWNER	PLANT LOCATION					PLANT OWNER	PLANT LOCATION				

ATTACHMENT 2

Source: Office of Coal Util.,
Adv. Conv. & Gasification
Fossil Energy Files

COAL WATER SLURRY RESEARCH AND DEVELOPMENT
STATE OF THE ART AS OF
SEPTEMBER 1984

PRIVATE SECTOR RESEARCH STUDIES	PRESENT CAPABILITIES/ACTIVITIES	APPLICATIONS/GOALS
COAL-WATER SLURRY		
NYCOL, SWEDEN	o Swedish process based on a license from Gulf & Western (froth flotation) process o 15 ton/day (U.S.) and 25 ton/day (Sweden) pilot plants are operating o 700,000 ton/year commercial plant planned o Site selected, seeking capital for commercial facility o Slurry 200 mesh o 80%+ mineral matter removed	o Large potential market in Sweden due to nuclear moratorium o Retrofit of oil designed boilers planned, district heating systems and utility boilers
CARBOGEL, SWEDEN	o 8 ton/hour pilot plant in operation o Advanced froth flotation cleaning techniques remove 75% of pyritic sulfur and ash down to 4% o Stable mixture containing 70% coal o Supplied coal water slurry for PFB tests in Leatherhead, England o Owned by Boliden, Sweden o Tested burner design in a 2.5 Megawatt hot water boiler	o Sold license to Canada o Canada planning a facility for coal-water slurry preparation in Nova Scotia. Fuels will be tested in an oil fired boiler at Chatham, New Brunswick o U.S. licensee is Foster-Wheeler Corporation
FLORIDA POWER AND LIGHT	o 120 day, full power test of Coal Oil Mixture, on a 400 MW, oil fired Utility Boiler at Sanford, Florida, completed o Planning a 120 day test of coal water mixture possibly on a modified coal oil mixture combustor o Firm has partially funded the Otisca T pilot plant in New York	o Desire to convert the existing oil fired units (>2000 MW) o Successful boiler conversion will provide a future market for slurry o Alternate fuels capability should provide control/improvement of costs

PRIVATE SECTOR RESEARCH STUDIES	PRESENT CAPABILITIES/ACTIVITIES	APPLICATIONS/GOALS
FLUID CARBON AB	o Svenska Fluid Carbon AB (Sweden), 3,000 bbl-of-oil equivalent/d commercial coal-water mixture plant in Malmoe, Sweden o Long-distance truck transportation of CWM o Full-scale testing of utility-size burners (up to 11 tons/hr/burner) performed on 400 MWe boiler in West Germany o Four (4) ton/d CWM pilot plant in Malmoe o Allis Chalmers (U.S.) recently finished construction of 7 metric ton/d Mobil CWM plant using fluid carbon technology o Allis Chalmers-Fluid Carbon have 3-4 ton/d CWM research plant in Oak Creek, Wisconsin o Research plant includes coarse grinding froth flotation beneficiation, classification and selective fine grinding, and slurry blending	o Retrofit oil fired boilers for coal water slurry applications o Fuel district heating systems and public utility boilers
ERGON	o ERGON, through a subsidiary called MICROENERGY, is participating in development work in the areas of micropulverized coal and coal water slurries o ERGON was the fuel supplier for a dry micropulverized coal firing test in a gas designed boiler at Mississippi Power and Light o A 1-1/2 ton per hour coal-water slurry pilot plant was scheduled to become operational in May of 1983	
COMCO	o Supplying 50/50 COM to phosphate ore drying operation o Supplying 50/50 COM to Florida Power Corporation o CWM agreement with Atlantic Research announced June 1984	

PRIVATE SECTOR RESEARCH STUDIES	PRESENT CAPABILITIES/ACTIVITIES	APPLICATIONS/GOALS
COALIQUID	o 12.5 tons/hr COM/CWM plant, Shelbyville, KY o 25 tons/hr COM/CWM plant, Mulberry, FL o Expanded CWM development o COM/CWM plant in Israel o COM/CWM plant under construction in Korea	o Establish new laboratory facilities in Louisville area o Modify Shelbyville plant to allow continuous CWM processing and triple current CWM capacity o Fabricate CWM combustion test facility at Mulberry, FL, plant o Boiler/furnace applications
STANDARD HAVENS	o Supplying CWM (Aqua Black) to asphalt manufacturer in Thornton, Cook County, IL	
RESOURCE ENGINEERING, INC.	o Low ash CWM process (>0.3% ash) o Process patent applied for o Currently testing in marine diesels	
SLURRY TECH, INC.	o Process patented by Alfred University Research Foundation o 100 tons of slurry containing up to 71% Eastern bituminous coals were successfully burned in various test furnaces o Plan to incorporate technology to achieve 500 cp at 75% test loading in pilot plant o 75 tons/day pilot operation yielded product with 2% ash and less than 1% sulfur o Conceptual design of a commercial scale plant is completed o Firm is co-funding the development and operation of a 2 ton/day continuous (Otisca T) pilot plant with Florida Power and Light o Slurrytech, Inc. and Babcock Power Ltd. of England have signed an agreement to build a 120,000 tpy coal water slurry demonstration plant near Nottingham, England. The CWS will contain approximately 74% coal, 25% water and 1% additive.	o Gain recognition for their slurry preparation technology o Develop a high performance, acceptable product for the present and future markets o See utility retrofit as near-term market and new industrial applications as long-term market

PRIVATE SECTOR RESEARCH STUDIES	PRESENT CAPABILITIES/ACTIVITIES	APPLICATIONS/GOALS
OXCE FUELS	o Occidental Research/Combustion Engineering o Operating a 1 ton/hour pilot plant in Windsor, CT o Have integrated coal beneficiation in the slurry preparation o Operating a 750,000 bbl/yr CWM plant in Jacksonville, FL	o Recognition for their slurry preparation technology o Develop a high performance product to capture initial sales market o Marketing philosophy unknown
ATLANTIC RESEARCH CORPORATION	o Slurry with less than 1% additive successfully tested at Babcock and Wilcox combustion test facility, Dupont test, & many other sites. o 600 bbl/day pilot plant in operation o Slurries from 20 types of coal including lignite and sub-bituminous coals have been prepared. o Considering the possibility of a cleaning technology in their slurry preparation process.	o Become recognized for their slurry preparation technology. o Capture major share of U.S. coal/water slurry market. o January 1983, announced plans for commercial preparation plant in Chesapeake, Virginia. o June 1984 announced agreement with COMCO.
ADVANCED FUELS TECH	Gulf & Western o ^(G&W)technology o Operating a 1 ton/hour pilot plant designed for coal oil or coal water slurry or dry cleaned coal. o Process is integrated with a coal beneficiation facility capable of 75% ash removal from most coals, and has successfully cleaned over 100 coals as feedstock ash and less than 1% sulfur depending on coal used. o December 1983, announced sale of technology and pilot plant to Standard Oil (SOHIO).	o Development of a product that would satisfy the NSPS ash and sulfur requirements. o Recognition for their slurry preparation technology.

BABCOCK & WILCOX	o Ongoing program for testing slurry from various suppliers in the laboratory o Test burn micro ground coals (44 microns or less) in laboratory facility. o Considered developing their own integrated coal cleaning/slurry preparation. o Cofunding slurry tech development of a process plant. o Slurrytech, Inc. and Babcock Power Ltd. of England have signed an agreement to build a 120,000 tpy coal water slurry (CWS) demonstration plant near Nottingham, England. The CWS will contain approximately 74 percent coal, 25 percent water and 1 percent additive.	o Measure the combustion characteristics, ash content, emissions, erosions and corrosion. Goal is to establish design criteria for new or retrofit boiler design. o Develop combustion characteristics of micro-ground coal. Data base for retrofit or design of new boilers. o Evaluate several existing concepts to determine costs and potential applications. o EPRI/Dupont performed a demonstration burn of 4 slurries on a commercial size (60,000 #/hr) oil-fired B&W boiler. Rheology and combustion characteristics under these conditions were defined.
OTISCA	o Heavy liquid agglomeration cleaning process is very efficient on coals tested to date. (98% yeild at 1% ash) o 200 #/hr. pilot plant in Syracuse under construction.	o Several slurry suppliers are considering the addition of the Otisca process to their slurry preparation operations. o Indicated efficiency should make slurry preparation cost more competitive with other fuels.
EPRI	o Combustion tests on 60,000 lbs/hr. industrial boiler completed. o Plan to fund combustion tests on utility scale boiler pending results of industrial boiler tests. o WEMCO o KHD (Germany) o Dow Corning o On-line Slurry Analyzer o Ontario Hydro	o Advanced CW technology as a primary utility fuel to replace oil and gas. o Get to utility demo on a fuel as soon as possible. o New Froth Flotation cell development. o New jig for fine coal cleaning. o Dewatering reagent o Rapid Coal Stream Analysis o Oil-Agglomeration Demonstration

ATTACHMENT 3

SURFACE COAL GASIFICATION PILOT PLANT, DEMONSTRATION, COMMERCIAL PROJECTS IN UNITED STATES

Source: OCUAC&C Files

Process	Facility Type	Contractor	Plant Location	Bed Type	Coal Type	Plant or Design Capacity TPH	Operating Pressure PSI	Product Gas Type	Status
Ammonia From Coal/Texaco	Pilot	TVA	Muscle Shoals, AL	Entrained	All	225 TPD	510	Synthesis	Operational Test Program in Progress
Kiln Gas	Demo	Allis Chalmers	Wood River, IL	Rotary	All	675 TPD	120	Low	Facility Constructed and in Operational test Progrm
Cool Water/ Texco	Demo	EPRI	Daggett, CA	Entrained	All	1000 TPD	600	Medium	Construction Completed in Operational Test Program
Great Plains Gasification Project/Lurgi	Commercial	Great Plains Gasification Associates	Mercer County, ND	Fixed	Lignite & Sub-Bit.	1400 TPD	430	High	Facility Constructed on Stream Delivering Product Gas
Chemicals From Coal/ Lurgi	Demo	Tennessee Eastman	Kingsport, TN	Entrained	All	900 TPD		Syngas	Facility Constructed and in Operation
Chemicals From Coal/ Texaco	Pilot Plant	Dow Chemical Co.	Plaquemine, LA	Entrained	All	200 TPD		Synthesis	Facility Constructed and in Operation

SURFACE COAL GASIFICATION
INTERNATIONAL PDU, PILOT PLANT, DEMONSTRATION PLANT PROJECTS

Country	Process	Plant Capacity Metric TPD	Location	Proposed Commercial Site	Proposed Commercial Capacity MTPP	Status
Federal Republic of Germany (FRG)	Shell Koppers	150	Hamberg	---	---	Earlier Commercial Plans on Hold or Abandoned
FRG	High Temperature Winkler	24	Frecher	Huerth-Berhenrath FRG	6700	No Government Support, Rheinbraun Constructing Commercial Facility
FRG	Sarr Berg. Otto	264	Volklinger Furstenhausen	---	---	Government Support Ended; No Commercial Plans Announced
FRG	RAG/RCH Texaco	144	Oberhausen Holten	Cool Water	---	Government Reported to be Interested in Commercial Project in FRG
FRG	RUHR-100 High-Pressure Lurgi	135	Dorsten	---	---	Government Support Ended; No Commercial Plans
FRG	KGN Fixed-Bed	2	Huckelhoven	Huckelhoven	5500	State Government Interested in Funding Project Through Demo
FRG	Kloechner Molten Iron	240	Ruhr Region	---	1900	Government Reported to be Interested in Supporting Commercial Demo

SURFACE COAL GASIFICATION
INTERNATIONAL PDU, PILOT PLANT, DEMONSTRATION PLANT PROJECTS

Country	Process	Plant Capacity Metric TPD	Location	Proposed Commercial Site	Proposed Commercial Capacity MTPP	Status
FRG	Partial Gasification	360	Stockum	Gerstein-welke	5500	Government Funding Ended Commercial Prospects Low
FRG	Steag/Lurgi Combined Cycle	---	---	Lunen	1700	Commercial Facility Shut Down for Economic Reasons
France	U-Gas Agglomerating	200	Mazingarbe	---	---	Construction to Start in 1985
Great Britain	British Gas Slagging Lurgi	800	Westfield, Scotland	---	---	British Gas Testing Demo Size Gasifier at Westfield, Scotland
India		144	Tricny	Tiruchira-dalli	---	Demonstration Unit Undergoing Testing
Japan	Sumitomo Molten Iron	60	Kashima	---	---	Future Plans Call for Construction of Demo
Japan	Mitsui 17-Gas		Kitakyusha	---	---	Pilot Plant Testing
Japan	Coal Mining Research Combined Cycle	40	Yubari, Hokkaido	---	1000	Pilot Plant Testing Phase
Soviet Union	Power Engineering High Speed Pyrolysis-Fixed	100-200	Kalingrad	Kansk Achinsk	175 MT/HR	Demo Plant in Construction

Attachment 3 Cont'd

LIST OF FOREIGN COAL GASIFICATION FACILITIES*

*List contains facilities which are currently operating or which have been shut down for less than five years

LIST OF FOREIGN COAL GASIFICATION FACILITIES

Location	Gasifier Type & Number	Dates	Coal Type	Product Gas (Application)	Capacity per Unit
Bulgaria					
Dimitroffgrad	Winkler 4	1951 to Present		Medium-Btu	16.1 MMSCFD
Stara Zagora	Winkler 5	1962 to Present		Medium-Btu	27 MMSCFD
Czechoslovakia					
Chomutov	Woodall-Duckham 14	? to Present	Lignite	Low-Btu (Metal Works)	Approx. 2 MMSCFD
East Germany					
Schwarze Pumpe	Lurgi 24	1966 to 1980	Lignite	Medium-Btu (Town Gas)	24 MMSCFD
Schwarze Pumpe	Winkler 6	1950 to Present	Lignite	Low-Btu	58 MMSCFD
Bohlen	Winkler 3	1938 to Present	Lignite/Coke	Syngas (Hydrogen)	27 MMSCFD
Bohlen	Lurgi 10	1940/43** to ?	Lignite	Medium-Btu (Town Gas)	Approx. 2.5 MMSCFD
Zeitz	Winkler 3	1941 to Present	Lignite	Syngas (Hydrogen)	20 MMSCFD
Karl-Marx Stadt	Koppers-Totzek 2	1966 to Present	Oil Residue (Coke)	Syngas (Ammonia)	13.4 MMSCFD
West Germany					
Luenen	Lurgi 5	1969/70 to 1979	Subbitum.	Low-Btu (Gas Turbine)	Approx. 65 MMSCFD
Great Britain					
Westfield	Lurgi 5	1960/62 to 1974	Bitum./ Subbitum.	Medium-Btu (Town Gas)	9 MMSCFD
Greece					
Ptolemais	Koppers-Totzek 6	1959/69/70 to Present	Lignite	Syngas (Ammonia)	6 to 9 MMSCFD

LIST OF FOREIGN COAL GASIFICATION FACILITIES

Location	Gasifier Type & Number	Dates	Coal Type	Product Gas (Application)	Capacity per Unit
India					
?	Wellman-Galusha 6				
Ramagundam	Koppers-Totzek (4 headed) 3	1980 to Present		Syngas (Ammonia)	19 MMSCFD
Korba	Koppers-Totzek (4 headed) 3	1972* Construction Close to Completion		Syngas (Ammonia)	19 MMSCFD
Talcher	Koppers-Totzek (4 headed) 3	1980 to Present		Syngas (Ammonia)	19 MMSCFD
Jealgora	Lurgi 1	1961 to Present	Various		
Asansol	Riley-Morgan 2	1952/68 to Present	Bitum.		
Madras	Winkler 3	1961 to 1979	Lignite (now oil)	Syngas (Ammonia)	17.8 MMSCFD
Portugal					
Lisbon	Koppers-Totzek	1956 to Present	Lignite/ Anthracite	Syngas (Ammonia)	Approx. 4 MMSCFD
South Africa					
Sasolburg (Sasol I)	Lurgi 17	1954/58/ 66/73/80 to Present	Subbitum.	Syngas (Liquid Hydrocarbons), Ammonia, Fuel Gas	33 MMSCFD to 100
Secunda (Sasol II)	Lurgi 36	1979/80 to Present	Subbitum.	Syngas (Liquid Hydrocarbons)	33 MMSCFD
Modderfontein (Johannesburg)	Koppers-Totzek 6	1974 to Present	Bitum.	Syngas (Ammonia)	Approx. 14 MMSCFD
Vaal Potteries	Wellman-Galusha 1	1955 to Present		Low-Btu (Furnace)	
Union Steel	Wellman-Galusha 7	1951 to Present		Low-Btu (Metal Works)	
Rand Brick	Wellman-Galusha 1	1949 to Present		Low-Btu (Brick-Kiln)	

LIST OF FOREIGN COAL GASIFICATION FACILITIES

Location	Gasifier Type & Number	Dates	Coal Type	Product Gas (Application)	Capacity per Unit
South Africa (Cont'd)					
Scaw Metals	Wellman-Galusha 1	1955 to Present		Low-Btu (Metal Works)	
Lydenburg	Stoic 1	1976 to Present	Bitum.	Low-Btu (Metal Works)	
Driefontein	Stoic 1	1973 to Present	Bitum.	Low-Btu (Brick Kiln)	
Pretoria	Riley-Morgan 7	1933/41 to Present	Bitum.	Low-Btu (Metal Works)	Approx. 2 MMSCFD
Dundee	Riley-Morgan 2	1950 to Present	Bitum.	Low-Btu (Glass Works)	Approx. 2 MMSCFD
Springs	Woodall-Duckham 2	? to Present	Bitum.	Low-Btu	
Meyerton	Woodall-Duckham 1	? to Present	Bitum.	Low-Btu (Furnace)	
Johannesburg	Woodall-Duckham 2	? to Present	Bitum.	Low-Btu (Steel Works)	
Stewarts & Lloyds	Woodall-Duckham	? to Present	Bitum.	Low-Btu (Steel Works)	
Escowit	Woodall-Duckham 3	? to Present	Bitum.	Low-Btu (Furnace)	
Mandini	Woodall-Duckham 2	? to Present	Bitum	Low-Btu	
Driefontein	Woodall-Duckham 2	? to Present	Bitum.		
Vereeniging	Woodall-Duckham 3	? to Present	Bitum.	Low-Btu (Refractory Works)	
Stewarts & Lloyds	Wellman-Incandescent	? to Present	Bitum.	Low-Btu (Steel Works)	
Cullinan	Wellman-Incandescent 4	1964/65/73 to Present	Bitum.	Low-Btu (?) (Refractory Works)	
Scaw Metals	Wellman-Incandescent 5	1963/68/75 to Present	Bitum.	Low-Btu (?) (Steel Works)	
Johannesburg	Wellman-Incandescent 6	1963/68/75 to Present	Bitum.	Low-Btu (?) (Metals Works)	
Alusaf	Wellman-Incandescent 6	1978 to Present	Bitum.	Low-Btu (?) (Metal Works)	

LIST OF FOREIGN COAL GASIFICATION FACILITIES

Location	Gasifier Type & Number	Dates	Coal Type	Product Gas (Application)	Capacity per Unit
South Africa (Cont'd)					
Grootfontein	Wellman-Incandescent 1	1970 to Present	Bitum.	Low-Btu (?) (Metal Works)	
South Cross Steel	Wellman-Incandescent 4	1968/76/80 to Present	Bitum.	Low-Btu (?) (Steel Works)	
Highveld Steel	Wellman-Incandescent 6	1968/76 to Present	Bitum.	Low-Btu (?) (Steel Works)	
USCO	Wellman-Incandescent	1973 to Present	Bitum.	Low-Btu (?) (Steel Works)	
Saiccor	Wellman-Incandescent	1973 to Present	Bitum.	Low-Btu (?) (Paper Works)	
Union Steel	Wellman-Incandescent 5	1965/68 to Present		Low-Btu (?) (Steel Works)	
Consolidated Glass	Wellman-Incandescent	1967 to Present		Low-Btu (?) (Glass Works)	
Thailand					
Lampang	Koppers-Totzek 5	1963/66 to	Lignite	Syngas (Ammonia)	Approx. 10 MMSCFD
Turkey					
Kutahya	Koppers-Totzek 4	1966 to Present	Lignite	Syngas (Ammonia)	Approx. 9 MMSCFD
Kutahya	Winkler 2	1959 to Present	Lignite	Syngas (Ammonia)	Approx. 9 MMSCFD
Istanbul	Woodall-Duckham 1	?	Lignite		
U.S.S.R.					
Salawad	Winkler 7	1950 to Present		Medium-Btu	21 MMSCFD
Baschkirien	Winkler 4	1950 to Present		Medium-Btu	57 MMSCFD

LIST OF FOREIGN COAL GASIFICATION FACILITIES

Location	Gasifier Type & Number	Dates	Coal Type	Product Gas (Application)	Capacity per Unit
Yugoslavia					
Jendinjenja	Wellman-Galusha 1				
Gorazde	Winkler 1	1952 to Present	Subbitum.	Syngas (Ammonia)	6.3 MMSCFD
Kosovo	Lurgi 6	? to Present	Lignite	Syngas (Ammonia)	11.2 MMSCFD
Zambia					
Kafue	Koppers-Totzek 4	1967/74/75 to Present	Bitum.	Syngas (Ammonia Methanol)	Approx. 9 MMSCFD
Under Construction/Engineering Design					
Brazil					
San Jeronimo	Koppers-Totzek 2	1984	Subbitum.		Approx. 34 MMSCFD
Campo Largo	Carbogas-Pentagono	1980	Subbitum.	Low Btu? (Fuel Gas)	3 MMSCFD
China					
Peking	Lurgi 4	1978 (order date)	Semi-Anthracite	Syngas (Ammonia)	Approx. 30 MMSCFD
Poland					
Katowice	Koppers-Totzek 3	1982/83	Subbitum.	Med. Btu (Fuel Gas)	35 MMSCFD
South Africa					
Secunda (SASOL III)	Lurgi 36	1984	Subbitum.	Syngas (Liquid Hydrocarbons)	33 MMSCFD

Attachment 4

APPENDIX A

TEST SITE DESCRIPTION(1)

Utility	PP S/N	Site No.	Location	MARKET SEGMENT R-residential C-commercial I-industrial S-specialty	INTERFACES ELECTRICAL GI - Grid Independent GI (2) - with MCU GC - Grid Connect	 THERMAL DHW - Domestic Hot Water PROC - Process Hot Water SH - Space Heat S - Storage
Atlanta Gas Light	8242	43	Marietta, GA	R - Dormitory	GC	DHW with S
Baltimore Gas & Electric	8265	25	Pikesville, MD	C - Restaurant	GC	DHW with S
Brooklyn Union Gas	8231/8236	34	Queens, NY	C - Airport Arrivals	GI (2)	DHW with S
	8270	98	Staten Island, NY	C - Hospital	GC	DHW
Central Hudson Gas & Electric	8248	87	Wappinger Falls, NY	R - Apartments	GC	DHW with S
Columbia Gas	8228/8229	68	Cambridge, OH	C - Hotel/ Restaurant	GI (2)	DHW, Pool Heat
Consolidated Edison	8263	90	Croton/Hudson, NY	C - Nursing Home	GC	DWH with S
Consumers Power	8227	45	Jackson, MI	R - Apartments	GC	DHW
Dayton Power & Light	8243	56	Vandalia, OH	C - Hotel	GC	DHW
Delmarva Power & Light	8249	106	Hockessin, DE	C - Nursing Home	GC	DHW, SH
Florida Power	8264	108	Orlando, FL	S - Electric Generating Plant	GC	DHW with S
Gasco	8262	70	Hololulu, HI	C - Hotel	GC	DHW
Georgia Power	8245	85	Gainesville, GA	C - Hospital	GC	DHW with S
IBM	8256	97	Kingston, NY	I - Cafeteria	GC	DHW

(1) International Fuel Cells, 40KW On-Site Fuel Cell Field Test Program: Data Submittal, GRI Agreement 5080-344-0308, Amendment 9, FCR-7136, Monthly Status Report No 3, April 15, 1985.

APPENDIX A

TEST SITE DESCRIPTION (CONT'D)

Utility	PP S/N	Site No.	Location	MARKET SEGMENT R-residential C-commercial I-industrial S-specialty	INTERFACES ELECTRICAL GI - Grid Independent GI (2) - with MCU GC - Grid Connect	INTERFACES THERMAL DHW - Domestic Hot Water PROC - Process Hot Water SH - Space Heat S - Storage
Memphis, Light, Gas & Water	8246	71	Memphis, TN	I - Photo Lab	GC	Proc with S
Mountain Fuel	8233	36	Layton, UT	I - Photo Lab	GI	Proc with S
National Fuel	8230/8238	18	Cheektowaga, NY	C - Hotel	GI (2)	DHW with S
Northeast Utilities	8235	38	Vernon, CT	S - Telephone Switching	GC	SH
Northwest Natural	8241	20	Portland, OR	C - Laundry	GC	Proc with S
Osaka Gas	8237	4	Osaka, Japan	C - Restaurant	GI	DHW with S
Pacific Gas & Electric	8239	55	San Francisco, CA	C - Office	GC	DHW
Peoples Natural Gas	8251	89	Omaha, NE	C - Office	GC	DHW with S, SH
Philadelphia Electric	8267	109	Philadelphia, PA	C - Variety Club	GC	Pool Heat
Public Service Electric & Gas	8254 8271	96 112	Avenel, NJ Princeton, NJ	I - Alum. Products R - Dormitory	GC GC	Proc with S
San Diego Gas & Electric	8234 8260	47 50	Carlsbad, CA Escondido, CA	C - Nursery C - Health Club	GC GC	Proc Pool Heat
Southern California Edison	8259	7	City of Industry, CA	C - Laundry	GC	Proc
Southern California Gas	8224/8225	77	Fountain Valley, CA	C - Health Club	GC	DHW with S
	8268	79	Fountain Valley, CA	C - Restaurant	GC	DHW with S
Southern Company Services	8247	101	University, AL	S - Recreation Ctr	GC	DHW with S
Tennessee Gas Pipeline	8257	107	East Bernard, TX	S - Gas Compressor Station	GI	Proc

APPENDIX A

TEST SITE DESCRIPTION (CONT'D)

Utility	PP S/N	Site No.	Location	MARKET SEGMENT R-residential C-commercial I-industrial S-specialty	INTERFACES ELECTRICAL GI - Grid Independent GI (2) - with MCU GC - Grid Connect	INTERFACES THERMAL DHW - Domestic Hot Water PROC - Process Hot Water SH - Space Heat S - Storage
Tokyo Gas	8261	9	Tsukuba, Japan	S - Gas Expo/ Restaurant	GI	DHW
United Power Association	8253	102	Willmar, MN	I - Food Processing	GC	Proc
Virginia Natural Gas	8269	111	Norfolk, VA	R - Dormitory	GC	DHW with S
Department of Defense Sites						
Ft Belvoir	8258	153	US Army Ft Belvoir, VA	S - Dining Hall	GC	DHW
Elmendorf AFB	8266	154	USAF Anchorage, AK	S - Base Power Plant	GC	Boiler Makeup
Sheppard AFB	8252	152	USAF Wichita Falls, TX	S - Dormitory	GC	DHW
Wright-Patterson AFB	8244	151	USAF Dayton, OH	S - USAF Musuem	GC	SH

APPENDIX B

POWER PLANT MILESTONES

Utility	PP S/N	Acceptance Test Compl.	Shipped	Installation Complete	Norm. Oper. Start	Decommission	Return Shipped
Atlanta Gas Light	8242	06/21/84	07/06/84	08/10/84	08/14/84		
Baltimore Gas & Electric	8226	10/25/83	11/08/83	12/09/83	01/09/84	11/15/84	11/30/84
	8265	11/08/84	11/29/84	12/04/84	12/17/84		
Brooklyn Union Gas	8231	04/07/84	08/22/84	10/17/84	11/05/84		
	8236	04/18/84	08/22/84	10/17/84	11/05/84		
	8270	01/23/85					
Central Hudson Gas & Electric	8248	08/17/84	09/04/84	10/12/84	12/06/84		
Columbia Gas	8228	11/13/83	01/30/84	05/30/84	06/01/84		
	8229	11/17/83	01/30/84	05/30/84	06/02/84		
Consolidated Edison	8263	10/31/84	12/13/84				
Consumers Power	8227	11/05/83	11/18/83	12/09/83	01/31/84		
Dayton Power & Light	8243	06/26/84	07/24/84	08/24/84	09/11/84		
Delmarva Power & Light	8249	08/27/84	09/18/84	09/26/84	10/18/84		
Florida Power	8264	11/04/84	12/11/84	01/18/85	01/29/85		
Gasco	8262	10/24/84	12/21/84	03/22/85			
Georgia Power	8245	07/13/84	07/27/84	08/15/84	09/05/84		
IBM	8256	09/25/84	11/07/84				
Memphis, Light, Gas & Water	8246	07/17/84	08/24/84	10/05/84	10/18/84		
Mountain Fuel	8233	01/06/84	02/09/84	03/02/84	04/03/84		

APPENDIX B

POWER PLANT MILESTONES (CONT'D)

Utility	PP S/N	Acceptance Test Compl.	Shipped	Installation Complete	Norm. Oper. Start	Decommission	Return Shipped
National Fuel	8230 8238	11/22/83 05/15/84	01/31/84 08/27/84	04/05/84 09/13/84	05/02/84 09/20/84		
Northeast Utilities	8235	01/31/84	04/25/84	05/04/84	05/17/84		
Northwest Natural	8241	06/06/84	06/26/84	07/06/84	07/16/84		
Osaka Gas	8237	05/02/84	07/23/84	10/29/84	11/09/84		
Pacific Gas & Electric	8239	05/31/84	06/18/84	08/29/84	10/11/84		
Peoples Natural Gas	8251	09/08/84	09/28/84	10/26/84	11/28/84		
Philadelphia Electric	8267	11/19/84	03/08/85				
Public Service Electric & Gas	8254 8271	09/21/84 02/05/85	11/06/84	12/23/84	01/23/85		
San Diego Gas & Electric	8234 8260	05/22/84 10/13/84	06/13/84 11/07/84	07/25/84 01/28/85	08/07/34 02/11/85		
Southern California Edison	8259	10/10/84	11/07/84	12/06/84	01/17/85		
Southern California Gas	8224 8225 8268	09/27/83 10/06/83 11/29/84	10/25/83 10/25/83 02/04/85	11/30/83 11/30/83 02/25/85	12/19/83 12/20/83 03/07/85	02/28/85	
Southern Company Services	8247	07/24/84	08/28/84	09/14/84	09/27/84		
Tennessee Gas Pipeline	8257	10/02/84	10/12/84	11/01/84	12/12/84		
Tokyo Gas	8261	10/19/84	11/05/84	11/27/84	12/10/84		

APPENDIX B

POWER PLANT MILESTONES (CONT'D)

Utility	PP S/N	Acceptance Test Compl.	Shipped	Installation Complete	Norm. Oper. Start	Decommission	Return Shipped
United Power Association	8253	09/18/84	10/08/84	11/12/84	11/29/84		
Virginia Natural Gas	8269	12/06/84	03/27/85				
Department of Defense Sites							
Ft Belvoir	8258	10/04/84	11/06/84	02/15/85	03/06/85		
Elmendorf AFB	8266	11/14/84	03/06/85				
Sheppard AFB	8252	09/12/84	09/28/84	11/12/84	12/18/84		
Wright-Patterson AFB	8244	07/02/84	07/24/84	08/31/84	09/20/84		
Spare Units	8232	12/14/83 01/16/85	01/31/84	-	-		02/08/84
	8250	01/07/85					

DON FUQUA, Florida, CHAIRMAN

ROBERT A. ROE, New Jersey
GEORGE E. BROWN, JR., California
JAMES H. SCHEUER, New York
MARILYN LLOYD, Tennessee
TIMOTHY E. WIRTH, Colorado
DOUG WALGREN, Pennsylvania
DAN GLICKMAN, Kansas
ROBERT A. YOUNG, Missouri
HAROLD L. VOLKMER, Missouri
BILL NELSON, Florida
STAN LUNDINE, New York
RALPH M. HALL, Texas
DAVE McCURDY, Oklahoma
NORMAN Y. MINETA, California
MICHAEL A. ANDREWS, Texas
TIM VALENTINE, North Carolina
HARRY M. REID, Nevada
ROBERT G. TORRICELLI, New Jersey
FREDERICK C. BOUCHER, Virginia
TERRY BRUCE, Illinois
RICHARD H. STALLINGS, Idaho
BART GORDON, Tennessee
JAMES A. TRAFICANT, JR., Ohio

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE AND TECHNOLOGY
SUITE 2321 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515
(202) 225-6371

MANUEL LUJAN, JR., New Mexico
ROBERT S. WALKER, Pennsylvania
F. JAMES SENSENBRENNER, JR., Wisconsin
CLAUDINE SCHNEIDER, Rhode Island
SHERWOOD L. BOEHLERT, New York
TOM LEWIS, Florida
DON RITTER, Pennsylvania
SID W. MORRISON, Washington
RON PACKARD, California
JAN MEYERS, Kansas
ROBERT C. SMITH, New Hampshire
PAUL B. HENRY, Michigan
HARRIS W. FAWELL, Illinois
WILLIAM W. COBEY, JR., North Carolina
JOE BARTON, Texas
D. FRENCH SLAUGHTER, JR., Virginia
DAVID S. MONSON, Utah

HAROLD P. HANSON
Executive Director
ROBERT C. KETCHAM
General Counsel
JOYCE GROSS FREIWALD
Republican Staff Director

May 21, 1985

Hon. William A. Vaughan
Assistant Secretary for Fossil Energy
U.S. Department of Energy
Washington, D.C. 20585

Dear ~~Mr. Vaughan~~ Bob

Thank you for your testimony before the Subcommittee on Energy Development and Applications on May 8, 1985. Attached are some additional questions that Members of the Subcommittee would like you to answer, in order to supplement the record of the hearing on this topic.

I would appreciate your responses to the hearing questions by June 4. If you have any questions regarding this request, please contact Mr. William T. Harvey, Jr., Subcommittee Staff Director at (202) 225-4494.

Sincerely,

Don

DON FUQUA
Chairman

DF:Hcw
attachment

POST-HEARING QUESTIONS AND ANSWERS

RELATED TO THE

MAY 8, 1985 HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY DEVELOPMENT AND APPLICATIONS

HOUSE SCIENCE AND TECHNOLOGY COMMITTEE

U.S. HOUSE OF REPRESENTATIVES

WITNESS: ASSISTANT SECRETARY VAUGHAN

Questions for Secretary Vaughan:

1. In your testimony, you indicate that several of the emerging technological options addressed in the submissions are currently being developed at near-commercial or commercial-scale without federal money. I would like to know which of these technologies are at this stage of development.

2. Before Congress does address the Clean Coal Initiative in a legislative context (i.e. consider legislation to appropriate funds for demonstrating these initiatives), I would like to say I share your concern over the interpretation of private sector "cost-sharing". I think it is only fair that the private sector be committed to sharing in all future costs (not counting their previous R&D efforts toward their contribution). Also, private sector contributions should be in the form of money. Donation of a facility is not sharing in the risk.

3. If demonstration projects are in fact brought on line in the near future, and if these facilities produce a product as well as offer a source for data collection, can DOE negotiate agreements that the private partner pay back the federal government for its share of assistance since the technology will be making money for the private entity?

QUESTIONS FOR SECRETARY VAUGHAN

Question #2: Before Congress does address the Clean Coal Initiative in a legislative context (i.e., consider legislation to appropriate funds for demonstrating these initiatives), I would like to say I share your concern over the interpretation of private sector "cost-sharing". I think it is only fair that the private sector be committed to sharing in all future costs (not counting their previous R&D efforts toward their contribution). Also, private sector contributions should be in the form of money. Donation of a facility is not sharing in the risk.

Answer: The Department of Energy fully endorses the concept of upfront and significant (greater than 50%) cost-sharing in the form of cash from day one of a demonstration project.

QUESTIONS FOR SECRETARY VAUGHAN

Question #3: If demonstration projects are in fact brought on line in the near future, and if these facilities produce a product as well as offer a source for data collection, can DOE negotiate agreements that the private partner pay back the federal government for its share of assistance since the technology will be making money for the private entity?

Answer: Repayment provisions can be stipulated in Government contracts. However, such provisions should not replace the requirement for significant upfront cost-sharing by the private sector in demonstration projects. Since repayment is never guaranteed and since it, in any event will likely occur many years into the future, should it occur at all, it cannot substitute for cost sharing.

Nonetheless, we agree that repayment clauses in addition to cost sharing are a logical and desirable component as applied R&D, even at stages somewhat earlier than demonstrations.

QUESTIONS
U.S. DEPARTMENT OF ENERGY'S REPORT ON EMERGING CLEAN COAL TECHNOLOGIES
May 8, 1985

Mr. Vaughan

1. There has been mention of using the National Coal Council in the Emerging Clean Coal Technologies Initiative. Please expand on this possibility. Please characterize that group as to occupations, coal industry experience, availability, and geographical representation.

2. In DOE's Emerging Clean Coal Technologies Report's assessment of alternative fuels, the potential for significant oil displacement by coal water mixtures is examined. The Report anticipates that the highest displacement will occur at the higher-risk end of the technology spectrum, including heat engine applications. The assessment concludes that this area "is prime for Federal stimuli and one for which DOE's program is focused.

   Please address how DOE is and intends to focus on stimulating research and development of the application of coal water slurries to heat engines.

3. Please respond to the statement in ERAB's report that, "Acceptance of coal water slurry by the utility industry will require further extended large scale combustion tests. The private sector seems to be ready to pursue this subject; however, the high cost of large-scale tests will require substantial DOE assistance."

4. ERAB's report recommends that DOE increase its efforts to co-fund programs aimed at waste utilization rather than disposal. How does DOE plan to respond to this recommendation?

5. Would it be within the Administration's definition of the "proper" federal R&D role for DOE to fund a test program in which the various coal locomotive concepts are demonstrated and compared in conjunction with the private sector to allow the private sector to pick the concepts most commercially feasible? Please respond to the points discussed in the following background.

   Background Such a program would fulfill Congressional and other requests for federal financial support of a coal locomotive prototype while minimizing the federal role in choosing between technologies. Such a program could be operated on a cost-shared basis with the combustion system manufacturers as well as with other interested private sector parties. Concepts suitable for such a program include, but are not limited to: AFB, coal-water mixture, pulverized coal, producer gas, coal-fired diesels and coal-gas turbines.

6. What is DOE's opinion on the comparative applicability of these concepts to locomotive use?

7. What are your views of the technical and international merits of the joint U.S. - China development of a new coal-fired steam locomotive? Please respond to the points discussed in the following background.

Background This concept is based on the competitive evaluation of applicable clean-combustion technologies in an existing Chinese production steam locomotive. Such a concept appears to have three significant advantages. First, it will introduce a commercially feasible, environmentally acceptable new coal-based locomotive to American railroads in the shortest possible time. Secondly, it is not locked into a specific coal combustion technology, but will promote joint coal-combustion technology development between the United States and China.

Questions from Congressman Rick Boucher

1) The appropriateness of clean coal technologies vary widely according to numerous factors including characteristics of the fuel, the age and size of the facility, and the emission reduction goal. Therefore, no one proposal could be expected to present the single technology for all purposes.

Would it be the intention of DOE to develop as wide a range of technologies as possible?

Would an integrative approach be taken whereby those technologies would be developed that could be joined together in different ways, for example coal cleaning with limestone injection multi-stage burners (LIMB), to achieve overall emmission reduction targets?

Specifically, what are the kinds of technologies with the greatest potential for integration with other kinds of technologies and for what kinds of applications?

2) The new report by DOE on the reserve states that DOE's previous experience with federal incentives have "with few, if any exceptions been unsuccessful in commercializing new fossil technologies." Federal support for energy technologies, however, have been apparently successful in a number of areas. Atmospheric fluidized bed technologies are now being commercialized. U.S. research and development on heat pumps and photovoltaics has been adapted and commercialized by the Japanese. Wall-fired LIMB technology has been successfully demonstrated by EPA with potential application to 40% of the utility market.

What has been the role of the federal government or other governments in the development and commercialization of these technologies?

Are there other examples of successful government demonstration and commercialization of energy technologies in this country or by other countries using either their own research and development or R&D results obtained by U.S. efforts?

3) Report language relating to the reserve clearly states that the purpose of clean coal technologies is "for using coal in electric utility and large industrial applications that reduce sulfur and other emissions resulting from such uses to levels that are required, or may be required, for compliance with the Clean Air Act, as amended (P.L. 98-473, Senate Energy and Natural Resources report 98-578)."

Given the limited amount of funds available for coal research and development and the desire to develop the widest range of clean coal technologies possible, would DOE try to emphasis proposals with the greatest potential yield in terms of market application and emission reductions?

Specifically, what technologies, if successfully demonstrated, would have the quickest market applications?

How long would market commercialization take for these technologies?

Specifically, what technologies if successfully demonstrated, would have the widest market applications?

To what extent could these technologies be expected to penetrate those markets?

Under these assumptions, what would be the overall emission reduction potential by kind of pollutant and economic activity of commercializing clean coal technologies?

Also under these assumptions, what technologies could, alone or in conjunction with other technologies, achieve the quickest reductions in emissions?

How long would it take to achieve the overall emission reduction potential of commercializing clean coal technologies?

4) The report of the Energy Research Advisory Board supports demonstration projects for clean coal technologies for electric utility retrofit applications.

Specifically, what would be the emission reduction potential of retrofitting electric utilities with clean coal technologies in terms of extent and timing of reductions?

5) Projections by the Energy Information Administration indicate that industrial use of coal, especially by industries with large, continuously operating boilers, is expected to increase substantially in the future. A recent report by the Office of Technology Assessment predicts that industrial emissions will be a significant portion of the total growth in emissions in the coming years.

Specifically, which industries have the particular need to develop clean coal technologies for expanded coal use or for compliance with Clean Air Act regulations?

What kinds of technologies are most appropriate for industrial applications?

How could new EPA regulations concerning "tall stacks" affect this need?

What industrial efforts are currently underway to meet these needs?

EPRI
Electric Power
Research Institute

July 1, 1985

RECEIVED

Mr. Don Fuqua
Chairman
U.S. House of Representatives
Committee on Science and Technology
Suite 2321
Rayburn House Office Building
Washington, DC 20515

Dear Mr. Fuqua:

Attached please find responses to questions transmitted in your letter of May 21, 1985 to Dr. Mannella. These supplement his May 8, 1985 testimony before the Subcommittee on Energy Development and Applications. I appreciate your and Mr. Harvey's patience in awaiting this response during my recent overseas travel schedule.

I am also attaching a copy of a recent briefing I gave to Senate staff concerning the Clean Coal Initiative. Some of the graphs and tables may be of interest to you and your staff.

Please contact me if I can be of further assistance.

Sincerely,

Kurt Yeager

Kurt E. Yeager
Vice President
Coal Combustion Systems Division

KEY:vbe

Attachments

cc: W. T. Harvey

3412 Hillview Avenue, Post Office Box 10412, Palo Alto, CA 94303 Telephone (415) 855-2000
Washington Office: 1800 Massachusetts Ave., NW, Suite 700, Washington, DC 20036 (202) 872-9222

Question 1:

When will the Paducah atmospheric fluidized bed combustion boiler construction be completed? Upon completion, what amount of operating experience will be necessary to convince the utility industry that the technology is ready for use?

Construction of the 160 MW atmospheric fluidized bed (AFB) demonstration at Paducah, Kentucky by EPRI, TVA, Duke Power, and the State of Kentucky will be completed in 1988. A basic test program of four years duration is planned. The first two years will focus on the factors needed to confidently design and operate the AFB technology across the electric utility industry. These include confirmation of heat transfer performance, plant controlability and safety, carbon utilization and emission control efficiency, operator-training, system design integrity and potential for scale-up in unit size. Thus, by 1990 confirmation of a confident design base for the utility industry and its suppliers should be available to reinforce the results of the current on-going 20 MW AFB prototype test program also at Paducah. The second two years will concentrate on testing alternative fuels and sorbents as well as determining the limits of off-design operating conditions and load change characteristics.

Following this basic performance test program, the demonstration power plant will be operated for at least an additional six years to monitor long-term component reliability and performance.

It should be noted that two additional large scale commercial applications of AFB technology are currently proceeding under private sector funding. These are the 125 MW Northern States Power AFB conversion and the 110 MW Colorado-Ute circulating AFBC repowering project. These projects will also include extensive demonstration testing to both complement the TVA demonstration and provide a broader range of design and operating conditions. In addition, a variety of AFB units in the 20 MW to 150 MW scale are being commercially implemented today as cogeneration projects with the electric utility industry or as repowering projects in electric utility plants.

Question 2:

What balance of funds in the DOE coal program would you suggest for the various ranks of coal in the United States? Bituminous, subbituminous, lignite?

The balance of funds among coal types depends heavily on the objective of the prgram being considered. The present DOE coal program, for example, focuses on "long range/high risk" technology development. Here a relatively even balance between bituminous and lower rark coals might be appropriate since coal production is shifting toward the lower sulfur, lower rank, Western coal where our knowledge base is relatively limited.

Also, many of the more advanced coal utilization technologies are less sensitive to coal type and thus would be more generally applicable to all ranks of coal.

In a program with more immediate demonstration and commercialization objectives, however, the funding balance might be more heavily weighted toward the bituminous rank of coal. The approximate production split among the three coal ranks today and their relative sulfur content may be summarized as follows:

	Production (10^6 Tons)	Greater Than 1% S
Bituminous	640	70%
Subbituminous	200	1%
Lignite	50	10%
	890	

In this regard, the type of technology being considered can also have a significant bearing. For example, coal cleaning technology may be quite different, dependent on the composition of the coal. Cleaning of bituminous coal will emphasize removal of ash and pyritic sulfur. Cleaning of lower rank coals, on the other hand, will emphasize coal drying methods plus removal of alkaline compounds affecting ash melting temperature. In comparison, fluid bed combustion, and to a lesser degree, coal conversion and flue gas scrubbing technology will be less dependent on coal rank or composition. Balancing of program funds according to coal rank must therefore consider these technology circumstances.

The following general balance by technology category is therefore indicated.

	Bituminous	Subbituminous	Lignite
- Coal Cleaning	50	35	15
- Flue Gas Cleaning	60	20	20
- FBC	33	33	33
- IGCC	50	35	15
- Combustion Technology	50	35	15
Average	50	30	20

Considering both utilization and technology suggests the following near-term balance of funds by coal type:

Bituminous	50-70%
Subbituminous	30-20%
Lignite	20-10%

Question 3:

What is the latest forecast in the utility industry on annual coal requirements in the year 2000, compared to the amount consumed by the industry in 1984?

In 1984 the electric utility industry consumed 664 million tons of coal to produce 1,342 billion kWh of electricity. This represents 85% of total U.S. coal consumption and 56% of U.S. electricity production. Based on a 2.5% per year industry projection of electricity demand growth, coal is expected to produce 2,100-2,300 billion kWh of electricity by the year 2000. This represents 58-63% of the forecast total U.S. electricity production at the end of the century. This, in turn, requires a growth in electric utility coal consumption to 1.0-1.1 billion tons per year.

The coal-fired electricity production in 1984 was achieved by 260,000 MW_e of generating capacity. By the year 2000, at least an additional 130,000-175,000 MW_e of new coal-fired generated capacity will be required to provide this forecast demand growth, assuming successful improvements in the availability of existing capacity.

Question 4:

What work has been performed to determine the relationship between degrees of cleaned coal and resulting boiler life, operating efficiency, and/or availability? What work is being done now on the relationship?

EPRI has initiated a major R&D effort to quantify the effects of coal quality on power plant performance. This effort involves: development of new, more effective measures of coal quality; cleaning of major steam coals in a controlled manner to provide combustion test coal samples with known mineral matter composition changes; pilot scale (3.5 million Btu/hr) combustion testing; and development of new diagnostic technology for direct, accurate measurement of phenomena occurring in full scale utility furnaces. To provide a methodology for predicting how coal quality changes will effect power plant generation costs, a project to develop a coal quality impact model has been started. This model is being based on a state-of-the-art survey of coal quality effects completed in 1984. Combustion testing completed or in progress includes:

- Illinois No. 6 coal in a joint project with a utility. Currently, this effort involves full scale tests on a 600 MW unit.

- Kentucky No. 9 coal.

- An Eastern Canadian coal (joint project with a Canadian Federal government).

Despite R&D underway, development of accurate techniques and data bases for predicting coal quality effects will take considerable time and resources. Further, it will require development of new analytical techniques (for both coal and combustion measurements) and probably a new type of combustion research furance(s). This will require an investment of at least $35 million over the next five years.

Question 5:

What work has been performed to determine the relationship between clean coal cost and flue gas cleanup cost? It would seem that cleaner, more expensive coal would require less expensive exhaust emission reduction. Please comment.

EPRI has used a case study approach to assess the impact of coal cleaning on new coal-fired power plants, but has not performed detailed analyses for the impact of combined coal cleaning and FGD on existing power plants. Cost models that will allow assessment of combined coal cleaning and FGD for existing plants are, however, being developed. Analysis of the existing plant situation is complicated because of: site effects, particularly, on the cost of FGD retrofit; until recently, lack of a good coal cleaning cost model; and, limited coal cleanability data.

Table 1 summarizes results from the EPRI new power plant case studies performed in 1980. This study considered seven coal-fired power plant combinations supplied with coal at three quality levels; Level A -- 50 mm x 0 run-of-mine (uncleaned) coal; Level B -- partially cleaned coal; and, Level C -- intensively cleaned coal. Table 1 summarizes the cost differences between firing Level A coal, uncleaned coal, and coal cleaned to Level C in new, 1000 MW power plants (twin 500 MW units). All plants are specifically designed to fire the specific coal supplied to them, either run-of-mine or clean coal.

In Table 1 the first column under Annual Generation Levelized Cost Savings, No Availability Increase, presents estimated levelized (levelized over 30 years) annual cost differences between plants firing run-of-mine and cleaned coal with assumed equal availabilities. Cost differences in parenthesis are negative values. The second column under Annual Generation Levelized Cost Savings presents estimated cost differences assuming that the plant firing clean coal realizes a 5-percentage point higher availability compared with the plant firing uncleaned coal. The Investment Cost Savings column presents estimated investment savings for plants firing clean coal. This savings includes the cost of both the coal cleaning plant and

TABLE 1
Potential Impact of Coal Cleaning on Power Plant Costs for Level C Coal Cleaning [1]

			Run-of-Mine Coal Composition [2]		Clean Coal Composition [2]		Annual Generation Levelized Cost Savings		
							No Availability Increase [3]	$5 Availability Increase	Investment Cost Savings [4]
Case No.	Coal Source	Power Plant Location	Ash wt%	Sulfur wt%	Ash wt%	Sulfur wt%	Million $/yr	Million $/y	Million $
1.	Illinois	Glasford, IL	16.5	3.4	9.2	3.2	(3.6)	3.9	1.5
2.	West Virginia	Bethlehem, PA	15.0	3.4	8.7	2.8	1.4	8.9	3.3
3.	West Virginia	Quincy, MA	16.0	0.8	5.5	0.8	8.1	15.6	11.7
4.	Alabama	Dade City, FL	27.0	1.3	12.2	1.3	12.5	20.0	26.0
5.	Montana	Freeport, TX	9.0	0.6	6.8	0.4	(1.0)	6.5	(14.8)
6.	Iowa	Panora, IA	15.1	6.9	10.2	4.7	(0.1)	7.4	(4.0)
7.	Utah	Delta, UT	22.9	0.6	8.4	0.6	4.8	12.3	26.4

Notes:

1. Level C represents intensive coal cleaning.
2. As-received basis.
3. No increase in availability between a plant designed to fire run-of-mine coal and clean coal.
4. Includes coal cleaning plant investment.

the power plant. In five of the seven cases, the investment required for the Level C coal cleaning option is less than for the uncleaned coal option. For these cases, the investment associated with coal cleaning was more than offset by savings in power plant investment requirements.

Question 6:

The Cool Water, California, integrated gasification combined cycle facility has operated at satisfactory rates since an uneventful start last year--significant performance. From this good beginning, how long will the facility need to operate to convince the utility industry of its commercial application?

In EPRI's judgement, a minimum of 8000 hours of successful operation will be required to achieve a confident basis for commercial application decisions concerning integrated gasification combined cycle (IGCC). This will encompass the first two years of the demonstration test program. The majority of the operation during this period will be on Utah low-sulfur bituminous coal with two months on Pittsburgh seam, eastern high sulfur bituminous coal.

An additional three years of test operation is planned to confirm equipment design and reliability. This is intended to provide the necessary basis for proceeding with commercial IGCC facilities at normal risk.

Mr. Sensenbrenner's Questions

Question 1:

In your testimony you seem to indicate that the system known as Pressurized Fluidized Bed Combustion has many advantages over other technologies, including the fact it is more cost effective and more efficient. In addition to controlling emissions, would you say that PFBC is the best demonstration project for the future and why?

PFBC has several advantages which make it a leading demonstration project for clean coal utilization. In addition to improved emission control, PFBC provides a unique opportunity for modular, transportable and quickly constructed power plants which can be used either as stand alone units or to repower existing plants. The result is both low unit capital and busbar energy cost plus better ability to match demand growth.

PFBC technology is maturing rapidly primarily through efforts in Europe. As a result, several utilities, including Wisconsin Electric Power Company (WEPCO) have proposed heavily cost shared PFBC demonstration projects for immediate implementation. EPRI strongly encourages the prompt implementation of PFBC demonstrations based on the progress in AFBC and PFBC development, bolstered by the active U.S. utility interest in PFBC. This step is necessary to make the technology available for commercial use by utilities in the 1990s when the demand for rapidly constructed, clean coal based, new generating capacity will be substantial.

Based on the performance attributes of PFBC, the quality and cost sharing of proposed-utility demonstrations, the manageable risks associated with the technology and its ability to prevent a potential electricity "generation gap" in the 1990s, we place it at the top of our list of clean coal technology demonstration requirements.

Question 2:

In your judgement, would the construction of one or more PFBC units in the next few years be enough to demonstrate its commercial viability?

Yes. This is based on our experience in the implementation of three complementary AFBC utility demonstrations which cover the range of design, fuels, and operating conditions faced by that technology. These demonstrations serve as the culmination of an extensive 10 year development program in AFBC for utility application. We believe a parallel PFBC program should be promptly implemented and can achieve the same degree of utility acceptance.

The PFBC demonstration program should therefore contain both a turbocharged PFBC boiler to repower an existing power plant, and a stand alone combined cycle PFBC installation. This would demonstrate the two complementary applications of PFBC power plant technology. In addition, it is recommended that the program support a circulating PFBC prototype boiler as a demonstration support facility.

As in the case of AFBC, this PFBC demonstration approach will build on the development program which has been underway for several years on PFBC boiler, turbine and hot gas cleanup technology. It would also recoup the development capability lost through the DOE aborted Curtiss-Wright PFBC pilot and the role-back in DOE support for U.S. boiler manufacturer testing at the Grimethorpe facility in the U.K. Finally, it would assure a viable domestic PFBC supply capability.

Question 3:

What do you see as the prospect for PFBC if there is no federal funding, and the utility industry has to go it alone?

Under current cost recovery restrictions, the regulated electric utilities cannot underwrite the full cost of large, first-of-a-kind, technology demonstrations. EPRI and the equipment suppliers have been able to help close the gap but government finan-ancial risk sharing is necessary if these demonstrations are to proceed in a timely manner. Most recently, AFBC and gasification - combined cycle demonstrations have been successfully implemented in this joint manner.

Unless such risk sharing participation by government is extended to PFBC, its availability to the electric utility industry will be delayed by 5 to 10 years. It would thus be unavailable to meet the major new electric generating capacity needs of the 1990s. Secondly, it would probably only be available then from foreign developers and boiler suppliers with domestic sources licensed from Europe. As such, it would place the hard pressed U.S. boiler manufacturers in an increasing difficult competitive position, make utilities dependent on foreign sources, and represent an ultimately very expensive drain on U.S. technology for coal utilization.

Question 4:

You mentioned in your appendix that one project being proposed is by Wisconsin Electric Power Company. I represent the District in which Wisconsin Electric Power Company proposes to construct the PFBC and I would like your appraisal of the WEPCO proposal.

The WEPCO proposal represents a direct application of an EPRI project evaluating alternative PFBC approaches. This EPRI project identified the turbocharged PFBC power plant design as the most cost effective, quickest to install, and least risk approach to the commercial implementation of PFBC technology. This evaluation effort concluded with preliminary engineering designs and cost estimates.

EPRI is pleased to continue this technical and financial participation in the on-going design phase of the proposed turbocharged PFBC demonstration to repower WEPCO's Port Washington Boiler No. 5. This directly translates the earlier, EPRI supported, engineering design to WEPCO's site specific application. In our judgement, the WEPCO demonstration represents a particularly attractive application of PFBC which can have broad and immediate value to the utility industry in the 1990's, if implemented promptly.

The participants in the WEPCO proposal have been leaders in the development of turbocharged boiler and PFBC technology. Their proposal reflects a well thought out program with a utility which has long been a leader in technology innovations for the utility industry. In fact, WEPCO demonstrated the first pulverized coal utility power plant in 1920 and has been the first to apply a variety of coal combustion improvements in the years since.

Briefing To Senate Staff

By Kurt E. Yeager
EPRI
Palo Alto, CA

June 19, 1985

SUMMARY COMMENTS

FIGURE 1 A kW of new generating capacity, in constant dollars, costs more than three times what it did in 1967 and even more than in 1920.

o This escalation results from the impact of increased environmental control, stretch out of licensing and construction schedules, loss of productivity, and resulting increases in interest charges during construction.

o As a result, fundamental improvements in power plant technology are required to substantially reduce these cost penalties. These improvements must more effectively integrate environmental control with the coal combustion process and provide smaller, modular plants with reduced construction times.

FIGURE 2 and 3 There is an urgent need for these improvements in power plant technology if growing national dependence on coal is to be satisfied. The increase in coal use by the year 2000 will be primarily in the electrical sector and reflects about 170,000 MW of new net coal-fired generating capability. Implicit in this projection are major improvements in energy conservation plus improved productivity from existing power plants. If these improvements do not occur then the need for new generating capability is even greater.

If this "generation" gap of the 1990s is to be resolved without major economic dislocation, a more aggressive national effort is required to demonstrate and commercialize the improved coal-based technology currently under development.

FIGURE 4 A variety of options for improving the cost and efficiency of emission control for existing and new coal-fired power plants are under consideration. These include commercially available physical coal

cleaning and flue gas wet scrubbing which reflect relative extremes in control efficiency and cost.

By comparison a variety of other developmental capabilities (reflected by the dashed lines) provide the potential for both substantially improved efficiency and reduced cost. In each case, prompt commercial application depends on demonstration.

Only in the case of Atmospheric Fluidized Bed Combustion (AFBC) and Integrated Gasification Combined Cycle (IGCC) are any substantial demonstration activities underway.

For those technologies whose function is solely environmental control, the levelized costs reflect total capital and operating cost (i.e., coal cleaning, dry sorbent injection, NO_x control, flue gas scrubbing). The levelized cost associated with AFBC and PFBC reflect that portion of total process cost directed to environmental control (e.g. 15-25%). Natural or syn-gas cost reflects the incremental cost of these alternative, very clean fuels.

A more complete description of these technologies and their demonstration opportunities are provided in Tables A, I, and II. Federal participation as a risk sharing investment banker is required to accelerate the first-of-a-kind demonstration of these improved options.

FIGURE 5
and 6

The advanced coal technology options (AFBC, PFBC, and GCC) all provide substantial opportunity to reduce the busbar cost of electricity relative to current pulverized coal power plants with flue gas scrubbing (PC and FGD). These savings are particularly dramatic for the smaller 200 MW size plant. This results from the increased opportunity for modularity and reduced construction time, in addition to savings in environmental control cost. The fuel flexibility of AFBC also adds an additional cost savings dimension. Capital cost savings (plant and envirionment) are greatest in PFBC re-powering applications where the technology can be used to supply additional steam to increase the output of existing power plants. Although the busbar cost savings of GCC is not as large, this is driven by the cost of natural or synthetic gas, not the power plant itself. GCC also provides the greatest environmental control potential of the various coal-based options.

Conclusions

- The nation stands at a threshold of fundamental change its technology base for coal-fired power plant generation. Coping with this transition will require an intensive, joint commitment over at least the next five years on the part of industry and government.

- There is no shortage of technical opportunities to improve the cost and environmental performance of coal utilization. The future is now and success depends on satisfying four objectives this decade:

  o Develop a confident scientific basis for decisions concerning the need and application of emission controls.

  o Demonstrate the array of potentially more effective retrofittable control alternatives to flue gas scrubbers. No one of these options will satisfy the range of conditions required by all coal-fired plants. As a set, however, they can meet this requirement and thus provide a necessary bridge during the transition to advanced, clean coal technology.

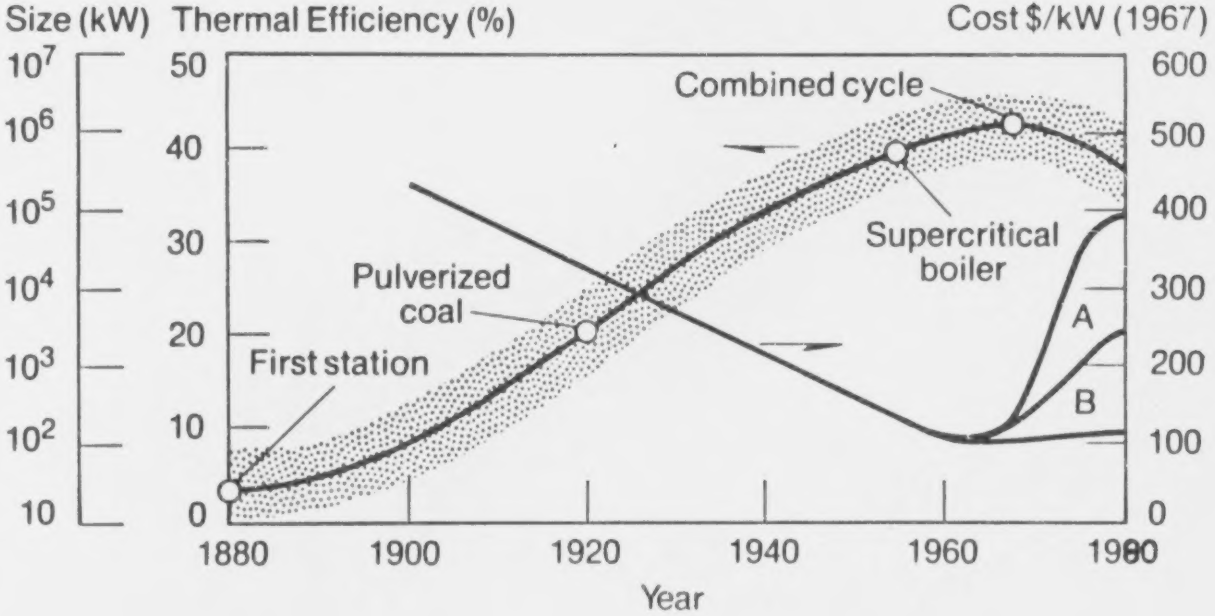
  o Demonstrate the advanced coal utilization technologies, e.g., AFBC, PFBC, and IGCC, which can fundamentally resolve the conflicts between coal and the environment while substantially improving efficiency and cost.

  o Establish incentives to encourage the prompt commercial implementation of these advanced technologies by the regulated electric utility industry.

- Experience has shown that Federal participation as a risk sharing investor in demonstration projects initiated and managed by the private sector has been the key to successful government/industry partnerships. Examples have been the TVA/EPRI AFBC and Coal Water IGCC demonstrations.

- Mechanisms which provide for prompt selection of proposed private sector demonstrations for Federal investment are critical to meeting the objectives of the Clean Coal Initiative.

POWER PLANT EVOLUTION

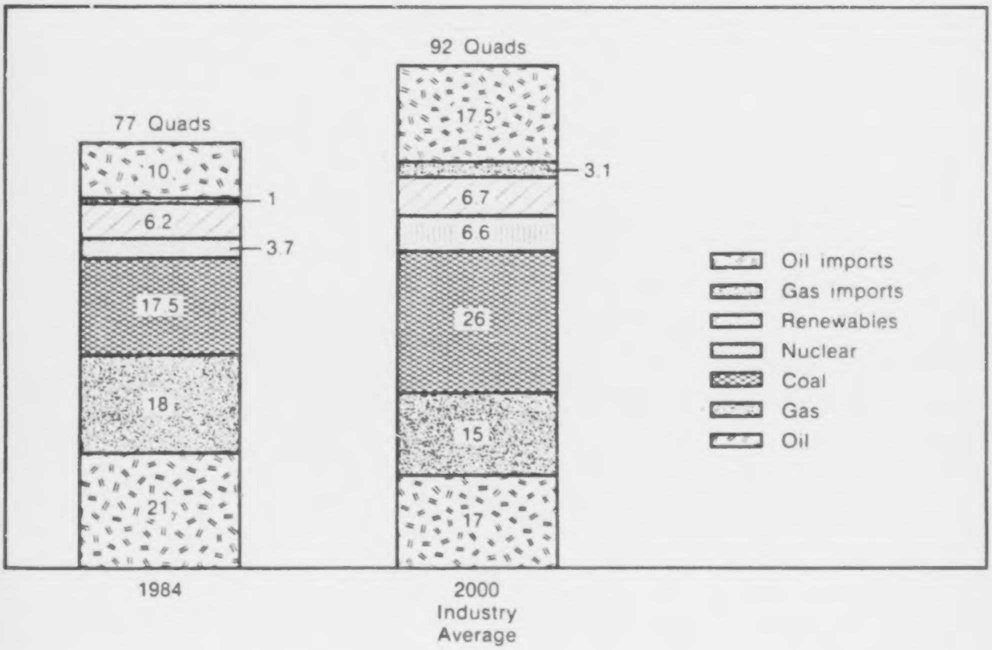


A = Environmental control cost

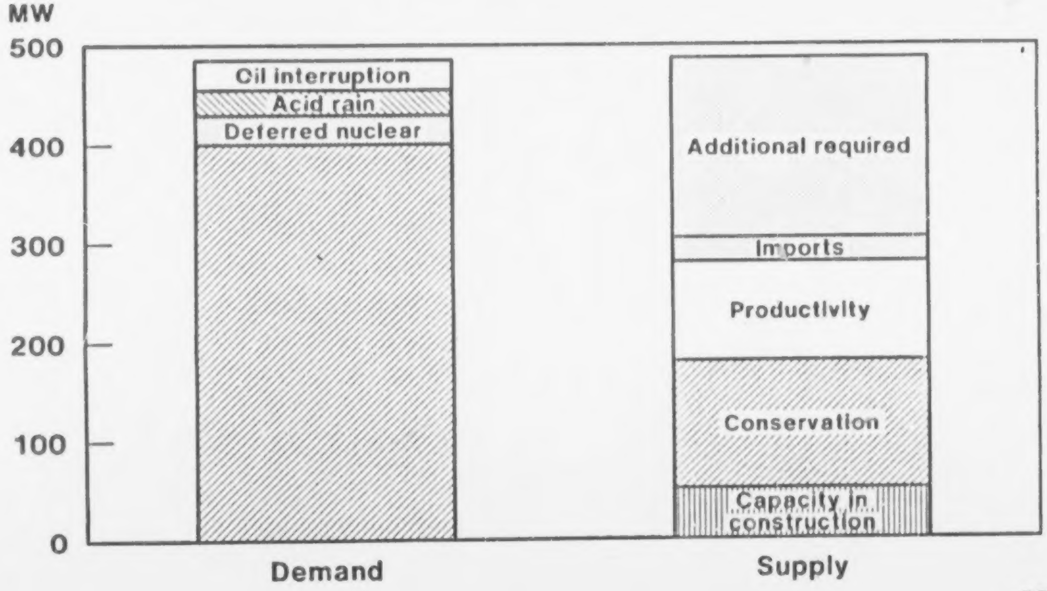
B = Impact of delays and losses in construction productivity

GP5811

COMPARISON OF PRIMARY
U.S. ENERGY CONSUMPTION
(Quads)

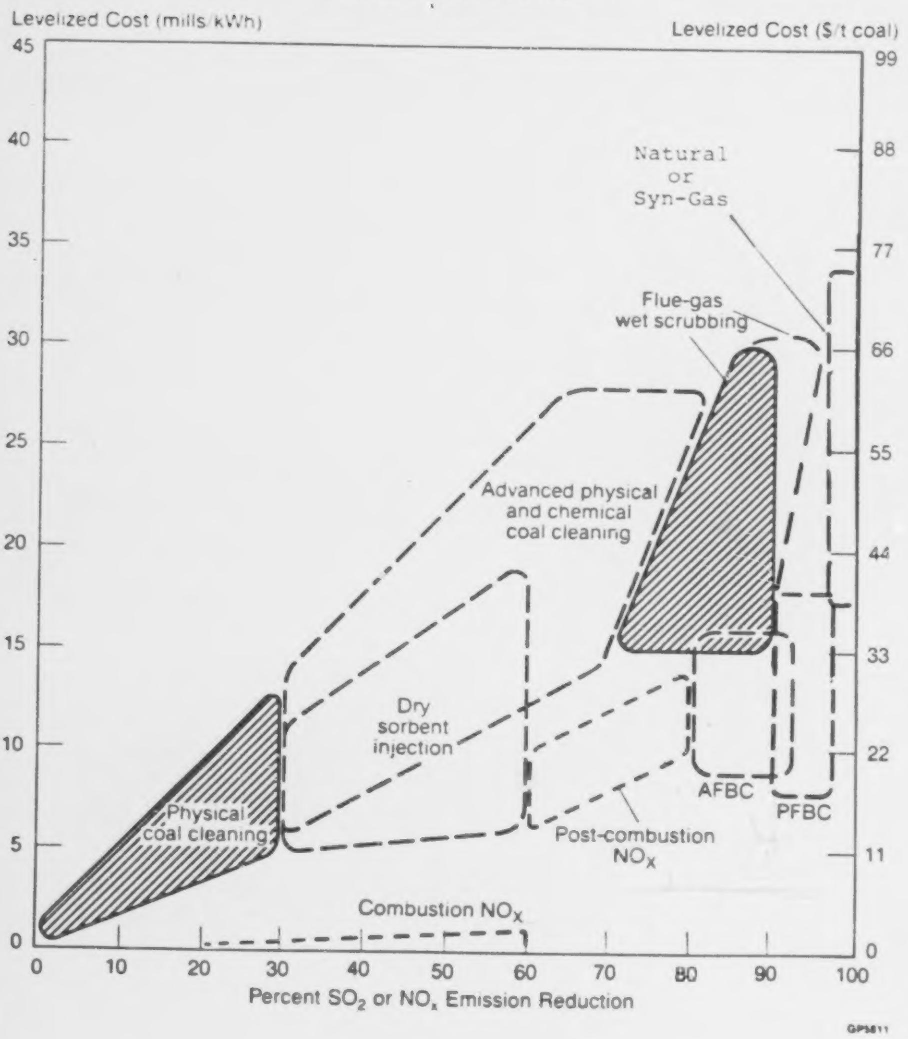


NEW CAPACITY SUPPLY AND DEMAND TO 2000 (3%/YR GROWTH)

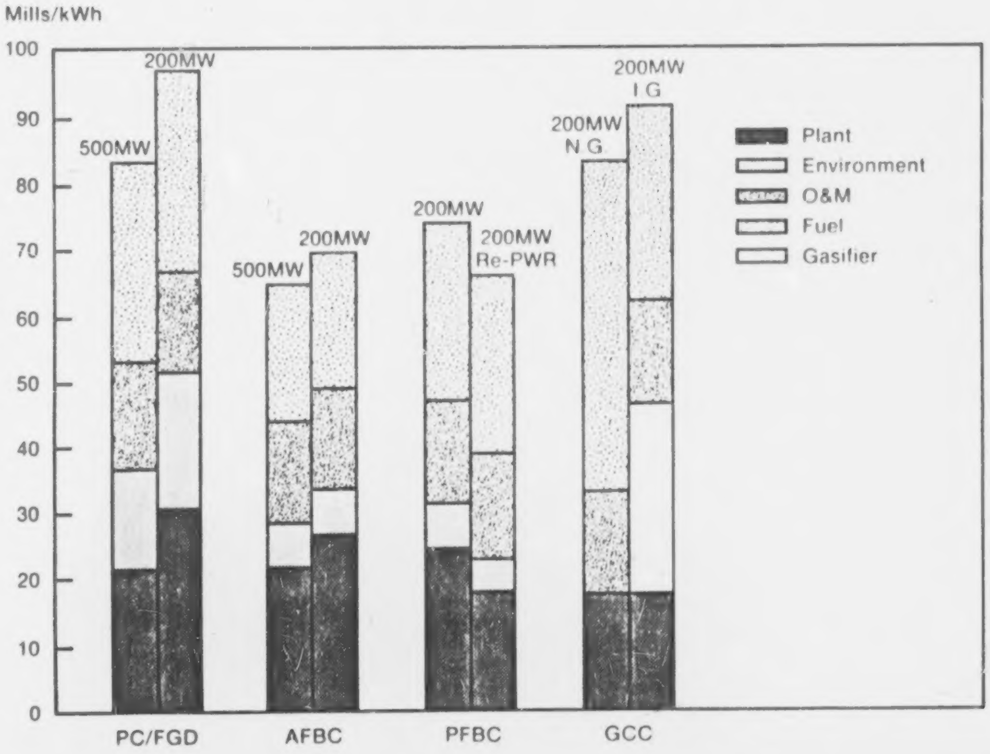


GG5472

COMPARISON OF COST & EFFICIENCY FOR EMISSION CONTROL



LEVELIZED BUSBAR COST
1985-2014



QUALITATIVE COMPARISON OF CHARACTERISTICS

Technology Characteristics	Adv PC/FGD	AFBC	PFBC	GCC	Fuel Cell GCC
Economical in Small Sizes	o	+	++	+	++
Fuel Flexibility	o	++	+	o	o
Low Emissions	+	+	+	++	++
Short Construction Time	o	+	++	+	++
Reduced Resource Use (water, etc.)	+	+	+	++	++
Higher Efficiency	+	o	+	+	++

Legend:

o Same as present conventional pulverized coal technology
+ Better than present
++ Much better than present

PROPOSED CLEAN COAL DEMONSTRATION AREAS INCLUDING EPRI PARTICIPATION
(Million $)

Technology Demonstration	Total Funding	Recommended Federal Participation
A. Coal Quality		
1. Intensive sulfur and ash separation	40	20
2. Efficient Fine Coal Cleaning & Recovery - EPRI CCTF	60	15
3. K - Fuel Cleaning and Pelletizing	39	10
4. Biological Coal Desulfurization	20	10
5. Automated Coal Cleaning Plant Process Control	20	10
B. Combustion Technology		
1. Coal-Water Slurry	50	20
2. Furnace Sorbent Injection for SO_2 Control (LIMB)	60	25
3. Low NO_x Combustion	25	10
4. Combustion Diagnostics and Coal Variability Impact Reduction	50	25
C. Flue Gas Cleanup		
1. Southern Company/Chiyoda 121 Process	40	10
2. EPRI High Sulfur Coal Test Center	35	5
3. Regenerable NO_x/SO_x Control	27	13
4. Baghouse Sorbent Injection for SO_2 Control	25	5
D. Pressurized Fluidized Bed Combustion		
1. Turbocharged PFB Boiler	90	45

2.	PFB Combined Cycle	120	60	
3.	Circulating PFB Prototype	70	40	
E.	Atmospheric Fluidized Bed Combuston			
1.	NSP Conversion	56	5	
2.	Colorado-Ute Circulating AFB	117	30	
3.	100 MW Coal Refuse Combustor	125	30	
F.	Integrated Gasification Combined Cycle			
1.	Slagging Gasifier & Advanced Turbine IGCC	440	180	
2.	IGCC Methanol & Electricity Production	40	20	
G.	Fuel Cell - Coal Gasification			
1.	Phosphoric Acid Fuel Cell	50	20	
2.	Carbonate Fuel Cell	150	90	
H.	Environmental Assessment			
1.	Impact Mitigation	20	5	
2.	Atmospheric Tracer Demonstration	200	40	
	Total	1969	743	(38%)

Table I

ILLUSTRATIVE RETROFIT COSTS (1)

Retrofit Technology	Capital Cost ($/kW)	Total Levelized Cost (mills/kWh)	Cost Effectiveness ($/ton SO_2 Removed)
Physical Coal Cleaning	20-45 (2)	3.6-0.9 (2)	336-923 (3)
Coal Switching			
Illinois to PRB	80-280 (4)	13.4-18.7 (4)	394-553 (4)
Illinois to Cent App	45	21.1	627
Illinois to Colorado	95	23.4	694
Limestone FGD	175-317 (5)	17.0-23.4 (5)	576-1126 (6)
Dual Alkali FGD	157-272 (5)	15.2-22.4 (5)	560-988 (6)
Chiyoda FGD	172-291 (5)	14.1-17.8 (5)	425-935 (6)
Forced Oxidation FGD	293-323 (5)	25.9-20.8 (5)	560-1048 (6)
Wellman-Lord FGD	252-492 (5)	21.7-31.5 (5)	754-1429 (6)
Spray Dry FGD	148-252 (7)	9.6-30.6 (7)	778-2831 (8)
Furnace Sorbent Injection	25-120 (9)	6.0-14.0 (9)	512-812 (10)
AFBC	70-245 (11)	9.5-17.6 (11)	550-1074 (11)
Post Furnace Injection	70-100 (12)	8.4-19.6 (13)	1462-2651 (14)
Post Comb NO_x	54-89 (15)	5.7-13.5 (15)	229-850 (16)
Low NO_x Burners	8-14 (17)	0.2-0.4 (17)	8-14 (18)
Coal Gasification	630-790 (19)	28-41 (19)	1595-2255 (19)

Table I (continued)

Notes

(1) All costs assume the following unless noted otherwise:

- End of year (EOY) 1982 dollars
- 30 year levelization period (1983-2012)
- 65 percent capacity factor
- 2 x 500 MW plant
- Midwest location
- 90 percent SO_2 removal

(2) Cost range for Level 4 cleaning (all size fractions) of an Illinois Basin or Northern Appalachian coal. Does not include capital cost of cleaning plant.

(3) 27 percent sulfur removal from an Illinois basin coal.

(4) Lower value assumes no derating; upper value assumes major derating. SO_2 removal range 85-88 percent. PRB means Powder River Basin.

(5) Lower value assumes an easy retrofit using 2 percent S-coal; upper value assumes a difficult retrofit on 4 percent S-coal.

(6) Lower value assumes an easy retrofit using 4 percent S-coal; upper value assumes a difficult retrofit using 2 percent S-coal.

(7) Lower value assumes an easy retrofit using 0.5 percent S-coal and 70 percent SO_2 removal; upper value assumes a difficult retrofit using 2 percent S-coal and 70 percent SO_2 removal.

(8) Lower value assumes an easy retrofit using 4 percent S-coal and 80 percent SO_2 removal; upper value assumes a difficult retrofit on 0.5 percent S-coal and 70 percent SO_2 removal.

(9) Cost range basis same as footnote 5 except 50 percent SO_2 removal assumed.

(10) Cost range basis same as footnote 6 except 50 percent SO_2 removal assumed.

(11) Capital cost range reflects fraction of total AFBC capital cost ($990/kW) accountable to environmental control. This ranges from 7% for SO_2 control alone to 25% for all aspects of environmental control. Total levelized cost includes cost of consumables (limestone waste handling). No capacity credit or fuel cost savings are included. Illinois No. 6 coal, 4% sulfur content.

(12) Costs shown are for new units assume a fabric filter retrofit is required. Retrofit costs could be higher.

(13) Lower value assumes a nahcolite system, reagent costs of $50/ton, 0.48 percent sulfur coal and 75 percent SO_2 removal; upper value assumes reagent costs of $150/ton, a 1 percent S-coal, and 75 percent SO_2 removal. Costs are for new units only; retrofit costs could be higher.

(14) Lower value assumes a nahcolite system, reagent costs of $50/ton, a 1 percent sulfur coal and 75 percent SO_2 removal; upper value assumes reagent (nahcolite) costs of $150/ton, 1 percent S-coal, and 75 percent SO_2 removal. Costs are for new units only; retrofit costs could be higher.

(15) Lower value assumes 60 percent NO_x reduction at 200 ppm inlet NO_x using 4 percent S-coal; upper value assumes 80 percent NO_x reduction at 800 ppm inlet NO_x using 0.5 percent S-coal. Costs are for new units; retrofit costs could be higher.

(16) Lower value assumes 80 percent NO_x reduction at 800 ppm inlet NO_x using 4 percent S-coal; upper value assumes 60 percent NO_x reduction at 200 ppm inlet NO_x using 0.5 percent S-coal. Costs are for new units; retrofit costs could be higher. Costs in $/ton of NO_2 removed.

(17) Lower value assumes retrofit of a face-fired or horizontally opposed-fired boiler; upper value assumes retrofit of a tangentially-fired boiler.

(18) Same assumptions as footnote 17; costs in $/ton of NO_2 removed.

(19) Capital cost range reflects costs of Texaco coal gasification and Integrated Gasification Combined Cycle (IGCC) plants reported in EPRI AP-3109. Raw coal cost of $1.89 MBtu, Illinois No. 6 coal, 4% sulfur content. No capacity or by-product credits are included.

Table II

RETROFIT CONTROL TECHNOLOGIES SUMMARY INFORMATION

TECHNOLOGY	COMMERCIAL STATUS	APPLICABILITY	SO_2 & NO_x REDUCTION POTENTIAL	CRITICAL ISSUES
PRECOMBUSTION CONTROL				
Physical Coal Cleaning	• Commercial	• Most economically applied to coals > 1% S	• 10 to 30% SO_2 reduction typical • up to 60% SO_2 reduction on easy-to-clean coals	• SO_2 reduction limited by pyritic S content • Benefits of cleaning need quantification • Potential heat rate penalty due to increased moisture content and fines loss
Coal Switching	• Commercial	• Cyclone and wet bottom boilers require low ash fusion temperature coal	• SO_2 reduction dependent on sulfur content of original and alternative coals	• Potential boiler derating due to fouling, slagging, and moisture content • Transportation costs • F.O.B. mine costs of low sulfur coal • Potential ESP upgrade • Potential pulverizer and coal handling equipment upgrade
COMBUSTION CONTROL				
NO_x Combustion Control	• Low to moderate controls commercially demonstrated (low excess air, overfire air, burners-out-of-service, biased firing, low NO_x burners) • Advanced low NO_x burners and improved furnace geometries currently nearing commercial status. Retrofit burners will be available for most unit types (except cyclones) by 1985	• Retrofit options not currently available for cyclone and wall-fired units with cell burners	• Low excess air - 0 to 15% • Biased firing - 5% • Burners-out-of-service - 20 to 25% • Overfire air - 15 to 25% • Low NO_x Burners 40 to 60%	• Several options must be available due to wide variety of boiler designs in operation • Retrofit costs and NO_x reductions attainable are highly site-specific
Furnace Dry Sorbent Injection	• Not commercially available in U.S. • Full-scale demonstrations underway in Europe	• Application may be limited by increased boiler solids loading	• 50% SO_2 removal likely; higher levels possible	• Process not fully characterized • Potential negative boiler impacts • Particulate control upgrading required • Potential adverse impact on ash handling and disposal systems

Table II (continued)

TECHNOLOGY	COMMERCIAL STATUS	SO_2 & NO_x APPLICABILITY	REDUCTION POTENTIAL	CRITICAL ISSUES
COMBUSTION CONTROL (continued)				
Atmospheric Fluidized Bed Combustion	• Commercial for industrial applications • 20 MW pilot plant in operation • 160 MW Demo scheduled for startup in 1989 • 125 MW conversion scheduled for 1986 start-up • 110 MW new circulating bed boiler scheduled for 1988 start-up	• Wide fuel flexibility • Approx. 150 boilers (20,000 MW) candidates for retrofit in U.S.	• >90% SO_2 removal • NO_x levels approx. 0.2 lb/10^6 Btu	• Fuel feed system • Turndown procedure • Tube erosion and materials longevity • Flyash recycle • Limestone utilization
POST COMBUSTION CONTROL				
Flue Gas NO_x Control	• Commercial in Japan for SCR - one operating system in U.S. on oil	• Applicable to all fossil fuel generation facilities	• 80% NO_x reduction for SCR • 30 to 60% NO_x reduction for thermal De NO_x	• Catalyst life (SCR) • SO_3 formation (SCR) • NH_3 slip and byproducts • Heat rate penalty • Reliability
Lime & Limestone FGD	• Commercial - over 60,000 MW in operation or under construction in U.S.	• Applicable to virtually all coals	• >90% SO_2 removal	• Retrofit costs typically vary from 1.1 to 1.4 times the cost of new units • Impact on plant availability • Retrofit may be constrained by space
Spray Dry FGD	• Commercial • 18 systems operating or planned (7500 MW)	• Applicable to virtually all coals	• ~90% SO_2 removal achievable on low S coal • ~90% removal indicated in short term tests on high sulfur coal (3.5% S)	• Baghouse or ESP improvements may be required for retrofit • Process not suitable for gypsum production
Dual Alkali FGD (Lime and Limestone)	• Commercial - three systems operating in U.S.	• Not applicable to low sulfur coal (<1.5% S) • Not applicable to gypsum production	• >90% SO_2 removal	• Limestone system difficult to control • Same space and plant constraints as lime and limestone FGD
Recovery of Salable Product FGD	• MgO (1 plant) and Wellman-Lord (2 plants) commercial in U.S.	• Applicable to virtually all coals • Most applicable to sites where byproduct disposal is constrained	• >90% SO_2 removal	• Markets for products must be available • Processes are relatively complicated and expensive

Table II (continued)

TECHNOLOGY	COMMERCIAL STATUS	APPLICABILITY	SO_2 & NO_x REDUCTION POTENTIAL	CRITICAL ISSUES
POSTCOMBUSTION CONTROL (continued)				
Advanced Throwaway FGD	• Horizontal - 4 systems in operation or under construction in U.S. • Chiyoda - 2 systems in operation or under construction • Saarberg-Hoiter - 4 systems operating in Germany • Co-current - several in Japan	• All applicable over wide range of coals and operating conditions • Additives may be advantageous in retrofits to offset design deficiencies	• >90% SO_2 removal	• Issues similar to those for lime and limestone FGD • Little U.S. experience for most of these systems
Post-Furnace Dry Sorbent Injection	• Field tested at 20 MW on low sulfur coal • 500 MW unit planned for 1990 start-up	• Potentially applicable to all coals. However, current sorbents may restrict use to Western plants due to cost • Pressure hydrated lime is under testing which may broaden applicability and removal efficiency.	• 70%-80% SO_2 removal on low S coal	• Sorbent availability - • Spent sorbent disposal - potential leaching of soluble sodium compounds

1019 19th Street, N.W.
Suite 910
Washington, D.C. 20036
202/887-0426

DAVID O. WEBB
Senior Vice President
Policy and Regulatory Affairs

June 4, 1985

The Honorable Don Fuqua
Chairman
Committee on Science and Technology
2321 Rayburn House Office Building
Washington, D.C. 20515

Dear Don:

I appreciated the opportunity to present GRI's views on the clean coal technology initiative before the Subcommittee on Energy Development and Applications on May 8. I have attached GRI's answers to the Subcommittee's questions regarding DOE's report.

If you need additional information, please call me.

Sincerely,

David

David O. Webb

Attachment
cc: William T. Harvey, Jr. ✓

Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois 60631 312/399-8100

RESPONSE TO QUESTIONS ON U.S. DEPARTMENT OF ENERGY'S REPORT ON EMERGING CLEAN COAL TECHNOLOGIES

May 8, 1985

Question: Surface coal gasification technology is conducted in a variety of methods--fixed-bed, fluidized-bed, entrained-bed--and at a variety of pressures. Specifically, what processes must be fully defined to characterize the technology, and what is the present status of each?

Answer: GRI interest in surface coal gasification processes is concentrated on current and emerging gasifiers suitable for economic production of substitute natural gas (SNG). Our economic analyses indicate that lowest cost SNG is achieved using processes that maximize production of methane within the gasifier, thereby reducing downstream processing costs. This is achieved in gasifiers that operate at lower temperatures and high pressures of 400 to 600 pounds per square inch (psi). Gasifier temperatures that control methane formation vary from approximately 900°F to 3,000°F and are dependent upon coal type, coal/steam/oxygen ratios, pressure, and the reactor configuration. The counter flow, fixed-bed (or moving-bed) gasifier will have nominal temperatures at the top of the bed in the range of 900°F to 1,200°F. Temperatures at the top of an ash-agglomerating fluid-bed gasifier will be 1,600°F to 1,900°F, and the reactor exit temperature for an entrained-flow gasifier will be 2,300°F to 3,000°F. At the very high temperatures associated with the entrained-flow reactors, methane is thermodynamically unstable and is generally not present in the product stream. At the lower temperatures associated with the fixed-bed and fluid-bed reactors, methane is more stable and will constitute a significant percentage of the gasifier product stream. Depending upon the specific coal and reactor conditions, as much as 40 percent of the final methane production can be achieved in the gasifier.

Lower operating temperatures also reduce oxygen requirements, which contribute to lower SNG cost. Operating pressures of 400 psi to 600 psi are compatible with the requirements of the gas clean-up and conversion processes downstream of the gasifier and, therefore, do not add unusual cost to the overall process. Operating pressures above 400 psi to 600 psi have diminishing impacts on SNG cost.

A coal gasifier is a very complex reactor. It operates at high temperatures, at elevated pressures, and is continuously fed gaseous streams and solid material that has both organic and inorganic constituents. In addition, it generates gas streams on a continuous basis that are both reactive and corrosive and discharges high-temperature ash on a continuous basis. Finally, a commercial reactor will have the capacity to process coal at rates of the order of 1,000 tons per day.

Because of the inherent complexity of these reactors, serious consideration of advanced technology for commercial applications will only occur when there is an adequate data base available that can be used to predict total systems performance and costs with a high degree of confidence and when the engineering risks have been reduced to a low level. This is due to the limited experience with reactors of these types and because of the large investments required for coal-to-SNG plants. The uncertainties associated with the scale-up of coal gasification technologies dictate that this data base must include both performance data (i.e., heat and material balances) and operational data on commercial- or near-commercial-size units.

Data needed to be developed include specific coal conversion rates, steam and oxygen feed rate requirements, carbon conversion, fines utilization and carryover, gas and ash composition, and reactor temperature variations. While each of these can be predicted from the results of smaller-scale experiments, uncertainties concerning flow profiles in the reactors and uncertainties with respect to gas-solids contacting make it difficult to predict large-scale gasifier performance to the degree required to accurately specify, design, and cost the other components of the plant.

In addition to the basic heat and performance data, the operational characteristics of the unit must be evaluated over an extended period of time. This is necessary to validate the reliability and operability of the engineering extrapolations in the harsh environments that exist in the different areas of the gasifier.

Based on GRI economic analyses, dry-ash, fixed-bed, slagging moving-bed, and agglomerating-ash fluid-bed gasifiers are the best candidates for SNG production. Entrained-bed gasifiers have the dual disadvantages of high oxygen utilization and essentially no methane production at any pressure because of their high operating temperatures.

Question: If the goal is to produce synthetic natural gas, which method or methods appear to be the most effective candidates?

Answer: GRI discussed the current and emerging processes of principal interest for SNG in our clean coal submission. We believe that the commercial Lurgi dry ash process will be adequately demonstrated by Great Plains if that plant continues operation. Briefly, emerging processes that are candidates for large-scale demonstration include the British Gas/Lurgi moving-bed, slagging gasifier and the agglomerating-ash fluid-bed processes Westinghouse and U-GAS are developing.

The slagging process is now approaching commercial scale (550 tons per day), in the UK, whereas both Westinghouse and U-GAS are at the process development unit (PDU) scale (24 tons per day). Even though larger-scale evaluation of U-GAS and Westinghouse technology (at 200 to 300 tons per day) is planned in France and China (respectively) in the next few years, neither of these planned projects address SNG as the end product. A large-scale demonstration of the agglomerating-ash fluid-bed process is urgently needed to provide operational data at higher coal throughput and/or operating pressure for agglomerating-ash gasifiers on eastern coals. This step is essential before these processes can be commercialized.

Question: You point out that 60 percent of the Emerging Clean Coal Technologies responses related to four technologies--flue gas cleanup, coal gasification, fluidized bed combustion, and coal preparation. What factors besides numerical response justify emphasizing support of those processes?

Answer: Additional factors that should be considered in determining which clean coal technologies should receive priority in any initial funding phase are:

1. The extent of cofunding offered by the industrial sector.
2. The involvement of technology users (not sellers) who ultimately determine its market acceptability.

3. The extent to which existing facilities are proposed in order to minimize total demonstration costs.

4. The cost-effectiveness of the proposed demonstration. In other words, the project should be the minimum size required to demonstrate technical and commercial feasibility; i.e., it shouldn't demonstrate at a 500-ton-per-day level if 200 tons per day is sufficient.

5. The potential for early commercialization if the technology is successfully demonstrated.

Question: Should Congress support demonstrations of other processes?

Answer: The longer-term, higher-risk processes proposed by some respondents should not be included in the initial phase of the program. These technologies, while promising, still require additional research and smaller-than-commercial-scale demonstrations before they can be commercialized. The initial program should be limited to processes which, if successfully demonstrated, could be moved immediately into the market in order to take advantage of the "window of opportunity" available between now and the early 1990s.

Advanced proccesses such as fuel cells, MHD, etc. should continue to receive research funding as part of the regular DOE Fossil Energy Program.

PEABODY HOLDING COMPANY, INC.
301 NORTH MEMORIAL DRIVE • P. O. BOX 373
ST. LOUIS, MISSOURI 63166
TELEPHONE (314) 342-3400

JOHN M. WOOTTEN
DIRECTOR
RESEARCH & TECHNOLOGY

June 3, 1985

The Honorable Don Fuqua
Chairman
Committee on Science and Technology
U. S. House of Representatives
Suite 2321
Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Fuqua:

The following is my response to the additional questions posed to me by the members of the Subcommittee.

1. As an investor in the Paducah Atmospheric Fluidized Bed Utility Boiler Demonstration, your company has shown active interest in an emerging clean coal technology. How long do you suspect the plant must operate satisfactorily to convince the utility industry that the technology is ready for use?

Answer: To respond to this question, I have reviewed the three fluidized bed demonstration projects - TVA, Colorado Ute and Northern States Power - to determine the length of their proposed test demonstration schedules. TVA has proposed a 48-month testing and commercial demonstration schedule; the first six months of that would be for shakedown, during which period the systems composing the FBC technology would all be brought into full service. Following this would be a 17-month parametric testing phase. This would be a phase for achieving operation at design conditions and for verification of design assumptions. The boiler and its subsystems would also be verified at various operating conditions. Following this will be a 24-month continuous commercial operation run. This run will assess the impacts that an extended period of operation under commercial conditions will have on the technology.

Colorado-Ute has proposed a 28-month program divided into two phases. The first phase would be operation at design conditions for verification of design assumptions and scale-up considerations. The second phase would be to test alternate fuels and sorbents (limestone) so that the data base for designing circulating fluidized bed units and the transfer of the technology to the utility industry would cover a number of representative fuels. Colorado-Ute has proposed that this testing phase be provided funding by the Clean Coal Technology Fund.

Northern States Power has proposed a 42-month test program. The first six months of this test program would be to guarantee the performance of the unit and would entail extensive testing by the boiler manufacturer to verify that the guaranteed performance conditions were being achieved. Following this would be a 3-year phase for testing various fuels and sorbents. It is anticipated that after testing with coal, a refuse-derived fuel would also be tested in the unit.

In summary, it appears that testing to insure commercial acceptability ranges for a period of two to four years, depending upon the complexity of the project. At least a 2-year test of a clean coal technology is required. That 2-year test should be broken into three major phases. The first phase being shakedown to ensure the opeation of the system itself; phase two would be operational testing at design conditions; and finally, phase three would be an extended opertional run under commercial conditions. The extent of a program would depend upon the complexity of the system as well as the desire for testing alternate fuels and, in the case of systems using a sorbent, alternate sorbents.

2. Among the several ranks of coal mined by your company, do you see any one as needing more R&D attention than the others? Why?

Answer: Existing and new markets of high sulfur bituminous coal require new technologies for environmentally acceptable and economically viable use of this coal. At the present time, these coals because of their sulfur content are at a disadvantage in the marketplace relative to lower sulfur bituminous and subbituminous coals. In addition, these coals retain this disadvantage when they are considered for use in new applications even though technology for sulfur removal is required on all new utility steam electric generating units. The cost to apply flue gas desulfurization systems to high sulfur coal is significantly larger than the cost to apply the same technology to a medium or low sulfur coal. In many instances, this differential between "scrubbing high sulfur coal" will more than offset the transportation differential that may occur when comparing a low sulfur coal to a high sulfur coal. Therefore, to ensure that the large midwestern and eastern reserves of higher sulfur coals can fulfill their traditional market role, clean coal technologies which can address this sulfur emission problem at a competitive cost must be developed.

3. It is estimated that total U.S. production in 1985 will approximate 905 million tons and that 1995 production must reach 1.2 billion tons to meet domestic and foreign needs. What amount of mining R&D will be necessary to assist the industry to increase production by one-third in ten years?

Answer: ICF has projected that the production of coal in the United States will reach 905 million tons in 1985. Beyond this 905 million tons of production in 1985, there will remain 54 million tons of excess production capacity in the East and 75 million tons of excess production capacity in the West, or approximately 130 million tons total. ICF further projected that the production level will reach 1,113 million tons in 1995. This means that the coal industry will have to expand by approximately 10% over the next ten years to exactly equal the required production level. In addition to this 10% expansion, it will be necessary to replace mines that deplete in that period in order to reach the required production levels. Therefore, it is unlikely that additional research will be required to meet the production goal. However, this is not to say that coal mining research is not required. There are a number of major areas where continued research is necessary. The areas are productivity, safety, environmental (reclamation and subsidence) and coal preparation. Because coal will continue to be the mainstay of the U.S. energy supply, it is important that adequate research, both private and public, be assigned to these areas.

4. What emerging clean coal technologies could have the quickest benefit to the coal industry?

Answer: This question needs to be addressed from two aspects, short-term and long-term benefits to the coal industry. In looking at the short-term or quickest benefits, the technologies which will reduce sulfur at a cost lower than present technologies, such as flue gas desulfurization systems or scrubbers, are the most desirable. Secondly, those systems that can combine both the removal of sulfur and nitrogen have a double benefit environmentally if it can be accomplished at a reasonable cost. A third factor is the need to have technologies which are retrofitable to existing facilities in order that these facilities, in the face of a major piece of environmental legislation or regulation, can continue to burn their historical fuel supplies. With those factors in mind, the following clean coal technologies will produce the quickest benefits:

Sorbent injection, either in the furnace or in the back pass of the boiler prior to the particulate collection equipment (electrostatic precipitator or baghouse);

limestone injection multistage burner (LIMB) applications to the various boiler configurations (wall fired, corner fired and cyclone);

dry scrubbing technology on high sulfur coal followed by particle collection either a baghouse or an electrostatic precipitator;

advanced physical coal cleaning for those applications where gas or oil-fired units can be converted to coal; and, finally,

atmospheric fluidized bed combustion and circulating fluidized bed combustion are alternatives for construction of new boilers as well as, in the case of AFBC, retrofitting to existing boilers.

These technologies will provide the quickest benefits to the coal industry. In the long run, however, chemical coal cleaning, the development of a slagging combustor for retrofitting to current oil and gas-fired units, the development of Pressurized Fluidized Bed Combustion and the second generation of gas turbines that utilize a coal or coal-derived fuel gas with hot gas cleanup are clean coal technologies which will enhance the use of coal in existing and new facilities.

5. What advice can you provide the Committee on possible addition, reduction or emphasis changes in the DOE coal R&D budget?

Answer: The response to this question is fairly straightforward when one reviews the projected FY86 expenditures for the DOE R&D budget. Projections are that approximately $150 million would be spent on coal-related R&D out of a potential expenditure of $2.8 billion, discounting weapons, naval reactor and defense R&D expenditures from the total $5.2 billion budget. The coal-related R&D expenditures are a mere 5% of the non-weapons related R&D budget. This small degree of expenditure does not compare with the proportion of this country's present and future energy needs which will be supplied by coal. Nuclear energy, for the time being, has faded in importance for supplying the country's energy needs over the next 10 to 20 years. Furthermore, the present price of oil has rendered the production of synthetic fuels non-enconomical for the private sector. This does not, however, relieve the concern of depleting domestic oil supplies and the increased use of imported oil. It would seem that a reemphasis away from nuclear and back to coal would be appropriate. The direct combustion of coal as well as new, lower-cost methods for producing synthetic fuels from coal would be an appropriate emphasis for the the reassigned monies.

6. To what extent are your utility customers willing to pay more money for cleaner coal - lower ash and sulfur? Could you envision providing coal at ash below 1% and sulfur below .1% and receiving premium pay from a utility which would not need to scrub the boiler exhaust gas or to use baghouses to meet clean air standards?

Answer: The attached table depicts 1980 delivered costs of coal by SO2 emission level for selected states. Data for 1980 was selected as a year in which demand produced costs which are representative of what one would expect to pay for premium fuels. As can be seen from the table, the differential between high and low sulfur coal can be considerable. It is this differential which can be classified as the premium a utility is willing to pay for a higher quality coal. It is evident and, I believe, extremely likely that a utility would pay a higher price for a coal quality that would allow them to avoid the use of flue gas desulfurization systems, that would reduce the amount of coal that would have to be handled and ground, as well as the amount of ash that would end up in the boiler and ultimately have to be disposed of. This premium would result primarily for conventional pulverized coal combustion. If an advanced technology, such as fluidized bed combustion were used, the fuel characteristics become less important. In fact, the use of lower quality coals becomes a positive point for these technologies. Atmospheric fluidized bed combustion is perhaps the most important of these in that the ash is required as a heat transfer medium within the boiler and only about one to two percent of the material in the boiler at any one instance is actually combustible material. The technology for removing ash from the flue gas is fairly simple and inexpensive and, therefore, premium fuels would not be required in these applications. The use of coal in an integrated combined cycle plant may or may not be influeneced by the amount of sulfur and ash in the fuel depending upon the type of cleanup systems required. As a general rule, the lower the ash and the lower the sulfur, the lower the operating cost for any system in which sulfur and ash must be removed. Therefore, utilities will pay a premium price to avoid the addition of control equipment or to lessen the operating costs of that control equipment.

If I can provide further information to you or the other Committee members, please contact me.

Sincerely,

John M Wootten

John M. Wootten

1980 DELIVERED COST OF COAL
BY SO2 EMISSION LEVEL
FOR SELECTED STATES

State	Cents/MM Btu: Less than 1.0 Lbs SO2/MM Btu	Cents/MM Btu: Between 1.1 and 3.0 Lbs SO2/MM Btu	Cents/MM Btu: Between 3.1 and 5.0 Lbs SO2/MM Btu	Cents/MM Btu: Greater Than 5.0 Lbs SO2/MM Btu
Alabama	241.9	197.6	199.4	172.2
Florida	---	249.9	187.4	---
Georgia	---	190.2	181.4	---
Illinois	251.1	272.2	149.1	153.0
Indiana	299.8	150.8	142.1	138.2
Kentucky	222.2	183.9	137.1	127.0
Michigan	206.0	210.3	156.9	---
Mississippi	307.6	235.3	196.1	---
Ohio	207.0	182.5	149.8	166.9
Texas	229.2	109.1	137.6	126.9
West Virginia	198.6	182.6	145.5	---
Wisconsin	180.4	172.4	177.6	165.4